Rulemaking: 06-02-013
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Exhibit No.: ______________________
Date: December 11, 2006

PACIFIC GAS AND ELECTRIC COMPANY

2006 LONG-TERM PROCUREMENT PLAN

ORDER INSTITUTING RULEMAKING TO INTEGRATE PROCUREMENT POLICIES AND CONSIDER LONG-TERM PROCUREMENT PLANS

VOLUME 1

PUBLIC VERSION
REDACTED

PACIFIC GAS AND ELECTRIC COMPANY
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SECTION I – EXECUTIVE SUMMARY

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SECTION I – EXECUTIVE SUMMARY

I. EXECUTIVE SUMMARY

Long-term procurement planning in California is becoming increasingly important and complex. Planning is important because, as loads continue to grow and existing generation continues to retire, adequate planning for California's energy needs is the only way to ensure reliable, cost-effective and environmentally preferred electric service for all Californians. At the same time, long-term planning has become increasingly complex. In addition to numerous California Public Utilities Commission ("Commission") and legislative directives regarding procurement, there are a wide variety of energy products, services and procurement alternatives to consider, as well as transmission and fuel issues. Numerous cyclical and structural uncertainties make long-term planning and procurement even more challenging.

This proceeding is critical because it provides California's investor-owned utilities ("IOUs") a forum to present detailed long-term procurement plans and to seek Commission approval of these plans, consistent with Public Utilities Code section 454.5. Over the past several years, the legislature and the Commission have often focused on resource specific issues – such as statutes addressing repowering, biomass or renewable energy and decisions focused on energy efficiency, solar initiatives or demand response. While these statutes and decisions are important, it is essential that procurement policy not be developed in a piecemeal fashion of set-asides and silos for particular resources. This proceeding provides the Commission with an opportunity to examine the larger procurement picture, over an extended period, and consider policies and plans to procure an optimal portfolio of reliable, environmentally preferred and reasonably priced energy for the next 10 years and beyond.

In Volume 1, Pacific Gas and Electric Company ("PG&E") submits its 2006 Long-Term Procurement Plan ("2006 LTPP") in compliance with the *Assigned Commissioner's Ruling and Scoping Memo on the Long-Term Procurement Phase of R.06-02-013*, issued on September 25, 2006 ("Scoping Memo"). Volume 1 includes a detailed description of PG&E's energy and fuel procurement plans and its proposal for implementing these plans.

PG&E's 2006 LTPP sets the stage for implementing the State loading order established in the Energy Action Plan ("EAP") and balances three primary objectives: (1) assembling a reliable and operationally flexible portfolio of resources; (2) supporting the development of environmentally preferred resources; and (3) managing customer costs. As with any planning process, there are trade-offs between these three objectives. PG&E's recommended plan was selected from a number of candidate plans based on a comprehensive evaluation of feasibility and performance metrics across multiple scenarios, keeping in mind PG&E's three primary objectives.

PG&E's recommended plan sets a path to: (1) invest in cost-effective and available Customer Energy Efficiency ("CEE"); (2) implement the California Solar Initiative ("CSI") and other distributed generation programs; (3) procure available demand response ("DR") sufficient to meet the Commission's 5% target; (4) procure renewable resources to and beyond the Commission's current 20% target; (5) invest substantially in transmission to support renewable resources; and (6) procure new dispatchable and operationally flexible capacity to ensure continued reliable service in northern California. PG&E's plan also promotes the development of environmentally preferred resources by supporting innovation in renewable technologies and enabling projects to go from demonstration to commercial viability through the proposed Emerging Renewable Resource Program ("ERRP"). In short, PG&E is recommending an ambitious long-term plan designed to provide reliable service, promote environmentally preferred resources and manage customer costs. While PG&E's scenario analysis demonstrates that market conditions have a much greater effect on rates than the choice of a plan that includes higher reliability or a greater emphasis on environmentally preferred resources, PG&E's recommended plan best manages customer costs while supporting important reliability and environmental policy objectives. The 2006 LTPP provided PG&E an opportunity to evaluate on a long-term basis the needs of its customers and all electric consumers in northern California and recommend to the Commission an integrated and comprehensive path forward.

In Volume 2, PG&E addresses a number of critical policy issues. In particular, PG&E addresses the impact of various legislative and regulatory events and requirements such as resource adequacy, implementation of greenhouse gas legislation, the California Independent System Operator Corporation's ("CAISO")

Market Redesign and Technology Upgrade ("MRTU"), Assembly Bill ("AB") 1576, PG&E's competitive procurement practices and credit policies, the use of an independent evaluator, gas hedging and risk management.

In addition, Volume 2 includes support for changes that PG&E is proposing to its procurement authority including: (1) increasing the Planning Reserve Margin to provide a more reliable electric supply; (2) modifications to PG&E's existing electric and gas hedging programs to manage customer costs; (3) adding a gas supply plan to ensure reliable gas supply; (4) adding a nuclear fuel procurement plan to ensure a reliable supply at reasonable cost; (5) creating an Emerging Renewables Resource Program to support development of new renewable energy technology; (6) implementing ratemaking proposal for the cost allocation method adopted under Commission Decision ("D.") 06-07-029; and (7) streamlining current Commission reporting requirements to improve the efficiency of the procurement process.

PG&E's 2006 LTPP is fully consistent with the requirements of Public Utilities Code section 454.5 (*i.e.*, AB 57) and should be approved as an up-front reasonableness standard for planned procurement transactions and eliminate the need for after-the-fact reasonableness reviews. To implement the 2006 LTPP, PG&E requests the following key approvals from the Commission:

- Approve the Increased Reliability and Preferred Resources Plan recommended by PG&E in Volume 1, Section IV.H;
- Approve PG&E's service area need determination provided in Volume 1, Section IV.E;
- Approve PG&E's use of the energy products identified in Volume 1, Section III.A.3 and its use of the markets and procurement and contracting methods described in Volume 1, Sections III.A.4 and A.5;
- Authorize PG&E to procure up to 2,300 MW of new dispatchable and operationally flexible generation resources to come online starting in 2011, as explained in more detail in Volume 1, Sections III.A.6 and V.F.6 and Volume 2, Sections I.B.1 and IV.B. This new generation is critical for ensuring continued reliability in northern California, especially if sufficient amounts of demand response are not available in the market;

- Approve PG&E’s electric and gas hedging plan described in Volume 1, Section III.B.1 and B.3 and Attachment III.A;
- Approve PG&E’s gas supply plan described in Volume 1, Section III.C.1 and Attachment III.B;
- Approve PG&E’s nuclear fuel supply plan described in Volume 1, Section III.C.2, Attachment III.C and Volume 2, Section IV.D;
- Approve PG&E’s credit and collateral requirements described in Volume 1, Section III.B.4;
- Modify the Planning Reserve Margins to a 1-in-10 year peak demand and 16 % reserves, as explained in Volume 2, Section I.B;
- Approve PG&E’s Emerging Renewable Resource Program described in Volume 2, Section I.B.5 and the associated ratemaking described in Volume 2, Section IV.G;
- Modify the current requirement that PG&E consult the Procurement Review Group (“PRG”) for all transactions that either begin deliveries more than three months in the future or have a term greater than three months to a requirement to consult the PRG for transactions that begin deliveries more than six months in the future or have a term greater than six months, for the reasons explained in Volume 1, Section II.D.1 and Volume 2, Section II.A.1;
- Modify the confidentiality rules to provide that PG&E does not need to disclose a winning bidder or project location when it files an application or advice letter to approve a project, for the reasons explained in Volume 1, Section II.D.1 and Volume 2, Section II.A.3.b;
- Synchronize the filing of PG&E’s California Department of Water Resources (“DWR”) gas supply plan with PG&E’s annual review of its electric portfolio gas hedging plan by specifying that the gas supply plan should be filed annually in the fall of each year, and encourage DWR to agree to the fall filing date, as described in Volume 2, Section III.A.1;

- Adopt PG&E’s ratemaking proposal for cost allocation under D.06-07-029 described in Volume 2, Section IV.E;
- Adopt the streamlined reporting recommendations proposed by PG&E in Volume 2, Section IV.F; and
- Determine that PG&E’s 2006 LTPP is in full compliance with the requirements of Public Utilities Code section 454.5.

In addition to approving these key elements of PG&E’s 2006 LTPP, PG&E also requests that the Commission consider in this proceeding a more global approach to its evaluation of procurement-related GHG issues. PG&E is committed to maintaining an electric portfolio with an emissions rate that is among the lowest in the nation through aggressive pursuit of energy efficiency, demand response, and renewable generation. While PG&E’s 2006 LTPP sets a path to meet all of the Commission’s demand response, energy efficiency and renewable energy targets, doing so may result in increased costs to customers. PG&E intends to aggressively pursue the Commission’s various procurement targets at the lowest possible price. In order to facilitate this, the Commission should consider establishing one GHG reduction goal, rather than creating further separate set-aside targets in renewables, distributed generation, solar roofs, demand response, repowering or energy efficiency. If PG&E has more flexibility in choosing among a suite of GHG-reducing tools, policy objectives are very likely to be met at a lower cost rather than if specific targets or set-asides are created in several programs.

Commission approval of PG&E’s recommended plan, associated products and procurement methods, and ratemaking will be a significant step toward the Commission and PG&E’s goals of ensuring reliable service, fostering the development of environmentally preferred resources and managing customer costs.[1] While PG&E recognizes that market conditions will ultimately dictate its ability to obtain preferred resources and to manage customer cost, PG&E believes that its

[1] In developing the 2006 LTPP, PG&E necessarily assumed certain market conditions, the availability of products, and the outcome of certain proceedings pending before the Commission. PG&E believes that its assumptions are well-grounded and reasonable. However, PG&E reserves the right to modify or change its proposed 2006 LTPP should new regulatory or market developments require PG&E to do so.

proposed 2006 LTPP provides the best opportunity to achieve PG&E's three objectives and provide the greatest benefits to northern California.

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SECTION II – BACKGROUND INFORMATION ON UTILITY PROCUREMENT

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II. BACKGROUND INFORMATION ON UTILITY PROCUREMENT

A. Introduction to Previous Procurement Plans and Procurement Plan Approvals

Pacific Gas and Electric Company's ("PG&E") 2006 Long-Term Procurement Plan ("LTPP") replaces short-term procurement plans ("STPP") submitted on May 1, 2002 ("2003 STPP") and April 15, 2003 ("2004 STPP"), as modified, and PG&E's long-term procurement plan submitted on July 9, 2004 ("2004 LTPP").[1] The 2006 LTPP plan incorporates all of the existing product and procurement implementation authority granted by the Commission in its decisions approving the 2003 STPP, 2004 STPP and the 2004 LTPP.

PG&E's prior procurement plans were the product of the Commission efforts in Rulemaking ("R.") 01-10-024 to enable each of California's three major investor-owned utilities ("IOU") to resume purchasing electric energy, capacity, ancillary services and related hedging instruments. In this section, PG&E describes its prior short-term and long-term procurement plans, and the Commission decisions approving these plans.

1. Transitional Procurement Authority for 2002

In Decision ("D.") 02-08-071, the Commission authorized the IOUs "to enter into contracts in participation with the California Department of Water Resources ("DWR") between the effective date of this decision [August 22, 2002] and January 1, 2003."[2] Characterizing this procurement authority as "transitional," the Commission authorized each IOU "to procure their forecasted on-peak hourly Residual Net Short ("RNS") requirement reflected in a low-case RNS scenario for products with options

[1] Filings at the California Public Utilities Commission ("Commission") are typically full of acronyms. Unfortunately, this filing is no exception. To assist readers, PG&E has included a list of acronyms used in this filing in an attachment to Volume 1, as well as the glossary requested by the Scoping Memo.

[2] D.02-08-071 at 2.

for multi-year contracts including ancillary services."[3] More specifically, the Commission authorized Southern California Edison ("SCE") and PG&E to purchase "(a) capacity contracts; (b) forward energy products; (c) transportation of the physical commodity portions to be delivered pursuant to authorized capacity and energy contracts; (d) related fuel products, natural gas supply, transportation, and storage for specific authorized capacity or energy contracts; and (e) energy exchanges, such as energy for capacity transactions, peak for off-peak exchanges, and seasonal exchanges."[4] The Commission also authorized the IOUs to use financially settled hedging instruments.[5]

With respect to Qualifying Facilities ("QF"), the Commission ordered that:

> IOUs are required to offer SO1 contracts, whose term ends at the time that the IOU fully implements its long-term procurement plan approved by the Commission, or on December 31, 2003, whichever occurs first, to any QF meeting the following conditions:
>
> - The QF must have been in operation and under contract to provide power with an IOU at any point between January 1, 1998 and the effective date of this decision.
> - The QF contract must be set to expire before January 1, 2004 or have already expired, or have been terminated.[6]

During the transitional procurement period, the Commission also required each utility "to procure at least 1% of their annual electricity sales through a set-aside competitive procurement process for renewable resources. Utilities must solicit bids with contract terms of five, 10, and 15 years, and enter into contracts with a mixture of lengths of not less than five years."[7]

2. The 2003 Short-Term Procurement Plan

When the Commission granted the 2002 transitional procurement authority, it was still considering procurement plans the IOUs submitted on May 1, 2002.

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[3] *Id.* at 15.

[4] *Id.* at 38, Finding of Fact No. 11.

[5] *Id.* at 38-39, Finding of Fact No. 12.

[6] *Id.* at 43, Ordering Paragraph 7.

[7] *Id.* at 43, Ordering Paragraph 6.

Subsequently, in October 2002, the Commission adopted each IOU's May 1, 2002 plan, as modified by Commission order.[8] In D.02-10-062, the Commission adopted a framework to enable the IOUs to resume full procurement responsibilities and authorized the IOUs to procure a variety of products summarized in Table 1 of the decision.[9]

The Commission recognized that the authority it granted in D.02-08-071 may not have been sufficient to enable the IOUs to procure their actual RNS needs and that "there is not enough time between the issuance of this decision and January 1, 2003 for the utilities to present thoughtful and realistic long-term procurement plans and have them approved by the Commission before beginning procurement…"[10] Accordingly, the Commission ordered the IOUs to file a "short-term procurement plan" on November 12, 2002 that was "to cover each utility's updated RNS needs" and "to cover only plans for activities to procure electricity in 2003 (though the actual power bought or contracted for in 2003 may cover needs for up to five years)."[11]

PG&E submitted its 2003 STPP on November 12, 2002, which the Commission approved with modifications in D.02-12-074. The specific products the Commission authorized PG&E to procure included: (1) real-time energy and ancillary services transactions in the California Independent System Operator's ("CAISO") markets; (2) day-ahead and hour-ahead spot energy and gas purchases and sales, and gas and electric transmission rights; (3) forward contracts for electric and gas purchases and sales, and gas and electric transmission rights; (4) the purchase and sale of electricity and gas options and financial swaps, such as firm transmission rights ("FTR"); and (5) inter-utility peak for off-peak seasonal exchanges or other, similar exchanges.

3. The 2004 Short-Term Procurement Plan

In D.03-12-062, the Commission approved PG&E's 2004 STPP.[12] The procurement products the Commission approved appear on pages 21-23 of the decision. The Commission also authorized the IOUs "to enter into contracts of up to

[8] D.02-10-062 at 70, Conclusion of Law No. 1.

[9] *Id.* at 37-38. *See also* Volume 1, Section III.A.3.a and b for a list of the products approved by various Commission decisions.

[10] *Id.* at 45.

[11] *Id.* at 46.

[12] D.03-12-062 at 87, Ordering Paragraph 1.

five years in term to meet needs occurring in 2004."[13] In addition, the Commission noted that it had authorized the IOUs "to serve as limited agents for DWR for fuel management services associated with DWR long-term contracts."[14] Finally, the Commission ordered that "QFs in operation and under contract to provide power to an IOU at any point between January 1, 1998 and the present day, whose contracts are set to expire before January 1, 2005, shall be afforded interim treatment, consistent with that provided in D.02-08-071."[15]

In D.03-12-062, the Commission also directed the IOUs to file advice letters updating their 2004 STPPs.[16] Accordingly, on January 20, 2004, PG&E filed Advice Letter 2464-E, which was supplemented by substitution sheets filed on February 24 and 27, 2004. The Director of Energy Division advised PG&E by a letter dated March 3, 2004 that Advice Letter 2464-E was effective as of January 20, 2004.

4. Extension of the 2004 Short-Term Procurement Plan Into 2005 and Beyond

In D.04-01-050, the Commission authorized the IOUs "to procure for 2005 under the same operational authority contained in the adopted 2004 short-term plans, except that authority for 2005 should be limited to the first three quarters, with contracting authority of up to one year in duration."[17] With regard to QFs, the Commission ruled that:

> [n]ew QFs may seek to negotiate contracts with utilities under the following circumstances: (i) voluntary QF participation in IOU competitive bidding processes; (ii) renegotiation by the QF and the IOU on a case-by-case basis of contract terms that explicitly take into account the IOU's actual power needs and that do not require the IOU to take or pay for power that it does not need.[18]

The Commission also ordered IOUs to provide updated forecasts of their 2005 open positions by advice letter.[19] On February 23, 2004, PG&E filed Advice Letter

[13] *Id.* at 79, Findings of Fact No. 13.

[14] *Id.* at 80, Finding of Fact No. 21.

[15] *Id.* at 88, Ordering Paragraph 14.

[16] *Id.* at 88 and 90, Ordering Paragraphs 12 and 24.

[17] D.04-01-050 at 196-197, Conclusions of Law No. 27.

[18] *Id.* at 198, Conclusions of Law No. 38.

[19] *Id.* at 201, Ordering Paragraph 9.

2477-E, which the Director of Energy Division accepted, effective February 23, 2004, by a letter dated December 17, 2004.

In D.04-12-048, the Commission extended PG&E's short-term plan authority stating that "[a]s for the STPPs, the 2006 LTPPs will contain the features of the Short-Term Plans that are not covered by the proposed 2004 LTPPs. That is, ultimately, we will eliminate the STPPs and the IOUs will act in accordance with a single Commission-approved plan. Until then, the existing STPPs will be in effect."[20]

In addition, in D.04-12-048, the Commission ruled that "[a]ny updates to the existing STPPs should be filed with an AL 30 days after issuance of this decision."[21] Accordingly, on January 18, 2005, PG&E filed Advice Letter 2615-E to update its 2005 STPP. In the advice letter, PG&E provided an updated list of products it intended to use in 2005 and incorporated all products approved by the Commission in D.04-12-048. By letter dated March 24, 2005, the Director of Energy Division notified PG&E that its advice letter was effective as of January 18, 2005.

On October 4, 2006, PG&E filed Advice Letter 2910-E to update its STPP with a revised list of authorized brokers and exchanges. Commission action on this advice letter is pending. PG&E will continue to update its STPP by advice letter until the Commission adopts PG&E's 2006 LTPP.

5. The 2004 Long-Term Procurement Plan

PG&E submitted a long-term procurement plan to the Commission on July 9, 2004. PG&E's 2004 LTPP covered the period from 2005-2014. In D.04-12-048, the Commission determined that PG&E's 2004 LTPP was reasonable[22] and authorized PG&E "to enter into short-term, mid-term, and long-term contracts, with contract delivery start date[s] through 2014, provided that [PG&E] submit[s] the necessary compliance filings."[23] The Commission also ordered the IOUs to "submit a compliance filing updating their procurement plans to reflect the changes and modifications adopted in today's decision."[24]

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[20] D.04-12-048 at 155-156 (emphasis added).

[21] *Id.* at 156.

[22] *Id*. p. 216, Ordering Paragraph 4.

[23] *Id*. at 219, Ordering Paragraph 14.

[24] *Id*. at 214, Ordering Paragraph 1.

On March 25, 2005, PG&E submitted Advice Letter 2643-E, updating its 2004 LTPP, and supplemented this submission by Advice Letter 2643-E-A, filed on April 1, 2005. The update included PG&E's projections of loads and supply and demand resources for a 10-year period and also included other elements such as updated annual energy and capacity balance tables, a summary of PG&E's procurement activity since July 9, 2004, updated energy efficiency targets, resource adequacy and local reliability requirements, and updated projections of natural gas prices.

6. Resource Adequacy Product Authority

On August 3, 2005, PG&E filed Advice Letter 2695-E, seeking approval of its proposed Resource Adequacy ("RA") Capacity Product contract language, and asked that proposal be deemed in compliance with its 2004 LTPP. On September 22, 2005, the Commission issued Resolution E-3955 granting the relief PG&E requested.

On September 1, 2006, PG&E filed Advice Letter 2897-E to update the 2004 LTPP's "List of Products and Transaction Types" to reflect recent Commission decisions related to PG&E's authorized RA products and to add a new product for trading RA import capacity counting rights. The advice letter also provides details regarding how PG&E plans to use its RA products in 2007 in accordance with D.06-07-031.[25]

7. Gas Hedging Authority

PG&E submitted its electric portfolio gas hedging plan to the Commission on July 15, 2005 by Advice Letter 2685-E, which the Commission approved on September 22, 2005 in Resolution E-3951. PG&E has updated the plan twice since that time by Advice Letters 2723-E (effective November 1, 2005) and 2775-E (effective March 17, 2006). The Director of Energy Division approved these updates by letters dated November 7, 2005 and March 17, 2006, respectively. Once the Commission approves PG&E's 2006 LTPP, a separate gas hedging plan will no longer be necessary because it will be subsumed within this plan.

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[25] D.06-07-031 at 45, Ordering Paragraph 3.

B. Introduction to Procurement Policy and State Law

1. California's Policy Framework for Energy Procurement

In the aftermath of California's devastating energy crisis, the legislature passed a comprehensive statutory scheme for the development and approval of energy procurement plans. Assembly Bill ("AB") 57, enacted in 2002, added Section 454.5 to the Public Utilities Code and included numerous requirements for electrical corporations and the Commission with regard to long-term planning.[26] In addition to establishing procurement planning criteria, AB 57 also provided assurance that if an electrical corporation followed its approved plan, it would not be subject to after-the-fact reasonableness review. Section 454.5 requires in relevant part that:

- Electrical corporations submit proposed procurement plans that include assessments of price risk, definitions of electric products and specific plans for product procurement, proposed incentive mechanisms, upfront standards and criteria for rate recovery, procedures for updating plans, achievement of certain renewables goals and portfolio diversity, risk management strategies, plans to increase ownership and fuel supply diversity, and a mechanism for recovery of administrative costs (§ 454.5(b));

- The Commission review and accept, modify or reject these plans, and ensure that the plan addresses competitive procurement processes, incentive mechanisms that establish a procurement benchmark and authorizes the electrical corporation to procure from the market, and/or up-front achievable standards and criteria for the "acceptability and eligibility for rate recovery" for bilateral transactions (§ 454.5(c));

- After-the-fact reasonableness reviews of actions in compliance with an approved procurement plan be eliminated, except for verification and assurance that contracts were properly administered and disputes reasonably resolved (§ 454.5(d)(2));

[26] Public Utilities Code section 454.5, enacted by AB 57, was amended by Senate Bill ("SB") 1976 on September 24, 2002 to change the required procurement resumption date. In 2005, SB 1037 further amended Section 454.5. While these amendments have added provisions and made some substantive changes, they have not changed the underlying requirements and purpose of the statute.

- The approved plan ensure timely recovery of prospective procurement costs incurred, moderate price risks and provide just and reasonable rates (§ 454.5(d)(3)-(5));

- The Commission periodically review electrical corporation procurement plans ((§ 454.5(e)); and

- The Commission adopt appropriate procedures to ensure confidentiality of market sensitive information submitted as a part of a proposed procurement plan ((§ 454.5(g)).

2. The Commission's Implementation of Its Procurement Authority

As described above in Volume 1, Section II.A, in October 2002, consistent with the AB 57 requirements, the Commission approved the IOUs' 2003 STPPs and created the Energy Resource Recovery Accounts ("ERRA") for the utilities to recover certain procurement related costs.[27] Shortly thereafter, in May 2003, the Commission, along with the California Energy Commission ("CEC") and the California Consumer Power and Conservation Financing Authority ("CPA") jointly issued the Energy Action Plan ("EAP"), setting forth goals for California's energy future and a commitment to achieve those goals through specific actions.[28]

In October 2005, the Commission and the CEC adopted Energy Action Plan II ("EAP II"), which describes a coordinated implementation plan for state energy policies articulated by the Governor, legislature, the CEC and the Commission.[29] The principles and plans identified in EAP II are now a critical part of PG&E's long-term planning process.

In February 2006, the Commission initiated this proceeding for the IOUs and other load-serving entities ("LSE") to submit long-term procurement plans for 2007-2016.[30] *The Assigned Commissioner's Ruling And Scoping Memo On The Long-Term Procurement Phase of R. 06-02-013* issued September 25, 2006 ("Scoping Memo") further defined the scope of the long-term plans that the IOUs

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[27] D.02-10-062, modified by D.02-12-074, D.03-12-062 and D.04-06-003.

[28] The EAP can be found at <htpp://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm>.

[29] EAP II can be found at <http://www.cpuc.ca.gov/PUBLISHED/REPORT/51604.htm>.

[30] R.06-02-013.

must submit. In particular, the IOUs' plans are intended to supersede all previous short-term and long-term plans and provide a single, comprehensive procurement plan for the 2007-2016 time period.

3. Recent Policies and Market Changes Impacting PG&E's Long-Term Procurement Plans

PG&E's procurement planning process does not exist in a vacuum. Instead, there are numerous legislative and regulatory processes, requirements and directives that affect PG&E's procurement plans. The following is a brief description of recent regulatory and legislative actions or decisions that PG&E considered in preparing its 2006 LTPP.

a. Resource Adequacy

In January 2004, the Commission issued a decision adopting a framework for resource adequacy requirements ("RAR") for all jurisdictional LSEs.[31] This framework includes a 15% to 17% Planning Reserve Margin[32] for jurisdictional entities. In October 2004, the Commission issued its first decision defining and clarifying the RAR framework.[33] In October 2005, after lengthy workshops, the Commission issued a further decision outlining the key requirements of a System RAR program.[34] At approximately the same time, in September 2005, the legislature passed AB 380 which codified a number of RA requirements for the IOUs, and other jurisdictional LSEs such as energy service providers and community choice aggregators.[35] The Commission's System RAR is designed to ensure that each LSE procures the capacity resources needed to serve its aggregate monthly system peak load, including reserves. Most LSEs are required to submit Year-Ahead and Month-Ahead reports demonstrating that they have satisfied their System RAR.[36]

In June 2006, the Commission adopted Local RAR for all LSEs, in addition to the System RAR it adopted in October 2005.[37] The Local RAR is intended to address

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[31] D.04-01-050 at 10-51.

[32] Based on a 1-in-2 year temperature peak load.

[33] D.04-10-035.

[34] D.05-10-042, *modified* by D.06-02-007 and D.06-04-040.

[35] AB 380 added Public Utilities Code section 380.

[36] Whether and how RA requirements will apply to small and multi-jurisdictional LSEs may be discussed as a part of Phase 2 of the Resource Adequacy proceeding.

[37] D.06-06-064.

local reliability issues and ensure that LSEs have sufficient resources in transmission-constrained areas. The Commission's decision required LSEs to satisfy Local RAR starting in 2007. Similar to the requirements for System RA, there are requirements for Year-Ahead Local RA filings.

The Commission recently addressed a number of outstanding RA capacity product and implementation issues[38] and has initiated Phase 2 of the RA proceeding to address further implementation issues and longer-term issues, such as a review of the existing program's sufficiency and consideration of capacity markets.[39] In developing its 2006 LTPP, PG&E incorporated the Commission's System and Local RAR so that PG&E will be in full compliance with the Commission's requirements, as well as AB 380.

b. Reliability Must-Run

Historically, the CAISO has contracted with generators in specified local areas to ensure local reliability. These contracts are referred to as Reliability Must-Run ("RMR") agreements. However, with the implementation of Local RAR, RA contracting should fulfill much, if not all, of the CAISO's local reliability needs. During a transition period, RMR is likely to continue and may be used by the CAISO when LSE contracting through the RA process is insufficient in meeting all the CAISO's local needs. This residual use of RMR, while the RA program develops, should be significantly less than historical RMR contracting volumes.[40]

c. Market Redesign and Technology Upgrade

On March 27, 2006, the CAISO filed its Market Redesign and Technology Upgrade ("MRTU") tariff at the Federal Energy Regulatory Commission ("FERC").[41] MRTU is a comprehensive re-design of the CAISO's markets and is intended to implement a day-ahead trading and scheduling system, create a new congestion management system, implement locational marginal pricing, improve market mitigation measures, modify scheduling protocols, and implement numerous other

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[38] D.06-07-031.

[39] *See e.g.*, *Administrative law Judge's Ruling Regarding Phase 2*, R.05-12-013, issued August 18, 2006.

[40] *See e.g.,* ISO Press Release, *California ISO Reduces RMR Contracts By 60%*, issued October 19, 2006 at http://www.caiso.com/1894/1894848a3e390.pdfhttp://www.caiso.com/1894/1894848a3e390.pdf.

[41] FERC Docket No. ER06-615-000.

changes in pricing and transmission access. The CAISO is proposing that MRTU take effect in November 2007.

FERC recently accepted the MRTU tariff, subject to a number of modifications, conditions and compliance filings to be made by the CAISO.[42] The CAISO is now proceeding with efforts to implement FERC's order and to develop and test the MRTU systems and software so that MRTU can become effective. The effect of MRTU on PG&E's procurement practices is still evolving. MRTU will add significant market complexity and will require major changes to PG&E's systems and software interfacing with the CAISO. While the full effect of MRTU is uncertain, PG&E is cautiously optimistic that it will not substantially impact the results of PG&E's resource planning and the majority of the procurement processes that typically happen in timeframes that extend well beyond the day-ahead and day-of focus of MRTU market changes. However, there are a number of elements of MRTU that remain open to change. Thus, MRTU is an important area of future uncertainty that will effect procurement and PG&E's planning process.

d. Community Choice Aggregation

Community Choice Aggregators ("CCA") are governmental entities formed by cities and counties to serve the energy requirements of local residents and businesses. The California legislature enacted AB 117 in 2002 to permit and promote CCA. CCAs are subject to certain statutory requirements, such as the RA requirements under AB 380, and the relationship between CCAs and the IOUs is subject to Commission rules and decisions. In December 2004, the Commission issued a decision addressing certain rate, tariff and cost allocation issues between the IOUs and CCAs.[43] In December 2005, the Commission issued a second decision that addressed issues including jurisdiction, tariffs and services, CCA implementation plans and some cost allocation issues.[44]

To date, there are no CCAs in PG&E's service area. However, a number of entities have expressed interest including the City and County of San Francisco ("CCSF"), the cities of Emeryville, Berkeley and Oakland, and a number of cities in Kings County. If any of these entities becomes a CCA, it could have a significant

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[42] *California Independent System Operator*, 116 FERC ¶ 61,274 (2006).

[43] D.04-12-046.

[44] D.05-12-041.

effect on PG&E's bundled load.[45] This is another area of uncertainty that PG&E has had to consider in its planning process. For purposes of the 2006 LTPP, PG&E considered various scenarios in which current bundled load customers depart from PG&E service to receive service from a CCA.

e. CAISO 95% Scheduling Requirement (Amendment No. 72)

In September 2005, the CAISO filed CAISO Tariff Amendment No. 72, which requires that Scheduling Coordinators submit day-ahead energy schedules that reflect 95% of their forecasted daily demand. FERC accepted Amendment No. 72 on November 21, 2005, subject to some modification.[46] While Amendment No. 72 affects PG&E's day-ahead scheduling and forecasting of resources and reduces the value of acquiring resources with intra-day operating flexibility, it does not affect long-term procurement plans or needs.

f. Commission Greenhouse Gas Policies and Recent Legislation

Since PG&E filed its 2004 LTPP, there have been significant developments at the Commission and the legislature regarding greenhouse gas ("GHG") emissions and global warming. In December 2004, the Commission directed the utilities to use a GHG adder in evaluating long-term procurement options and described its expectations for the development of a GHG reduction policy in the future.[47] The EAP II issued in October 2005 discussed specific steps the Commission and CEC intended to take to address GHG and global warming. At the same time, the Commission also issued a *Policy Statement on Greenhouse Gas Performance Standards*, which initiated an investigation into the integration of a GHG performance standard and procurement. In February 2006, the Commission issued a decision indicating its intent to develop a load-based GHG emissions cap.[48] The load-based

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[45] PG&E's bundled load includes all customers that receive transmission, distribution and energy services from PG&E. Direct access and CCA customers receive transmission and distribution service from PG&E, but do not receive energy services.

[46] *California Independent System Operator*, 113 FERC ¶ 61,187 (2005), *aff'd*, 115 FERC ¶ 61,168 (2006).

[47] D.04-12-048 at 155.

[48] D.06-02-032.

cap would apply to all LSE resources procured to serve load, no matter what the source, including imports.

The California legislature and Governor Schwarzenegger recently enacted two key pieces of legislation that will affect LSE procurement. First, SB 1368 directs the Commission to establish GHG emission performance standards by February 1, 2007 (in consultation with the CEC and California Air Resources Board), to consider the reliability and cost impact of these new standards, and to include certain design elements in the GHG standards. SB 1368 also prohibits the Commission from approving long-term (*i.e.*, five years or more) commitments for physical power by an LSE unless the base-loaded generation supplied complies with the GHG performance standards. Second, AB 32 establishes a comprehensive framework for the reduction of GHG in California for all industries, including utilities, through GHG emission limits, reporting requirements and potential market-based compliance mechanisms.

Although the California Air Resources Board has the primary responsibility for implementing AB 32, the Commission has indicated its intent to implement relevant portions of SB 1368 and AB 32 in Phases 1 and 2 of R.06-04-009. A Phase 1 draft decision implementing the performance standard on new long-term, baseload commitments is expected in early December with a final decision occurring in January 2007. In preparing the 2006 LTPP, PG&E has taken into consideration the Commission's GHG policies and decisions, SB 1368 and the potential impacts of AB 32.

g. Commission Renewables Procurement Decisions and Recent Legislation

The Commission initiated the Renewables Portfolio Standard ("RPS") in August 2002 by ordering each IOU to procure at least an additional 1% of its actual energy and capacity needs from renewable generation.[49] The Commission expanded the RPS program in 2003 and opened a rulemaking in 2004 to continue the implementation of the RPS program.[50] The Commission issued numerous decisions in the rulemaking and established a requirement that the utilities procure 20% of their total energy sales from renewable resources by 2010, and that the utilities increase renewable procurement by at least 1% of total sales per year until 2010. In

[49] D.02-08-071.

[50] D.03-06-071; R.04-04-026.

February 2006, the Commission opened a rulemaking to consider implementation of the RPS standards for Energy Service Providers ("ESP"), CCAs, and small and multi-jurisdictional utilities.[51] In May 2006, the Commission closed R.04-04-026 and initiated a new proceeding to continue to address RPS implementation and design issues.[52] The Commission recently issued a decision on counting, D.06-10-050.

The California legislature and Governor Schwarzenegger have also recently enacted legislation addressing renewables procurement. SB 107 requires that LSEs obtain at least 20% of the total electricity sold to retail customers from eligible renewable energy resources by 2010. SB 107 also includes a number of provisions addressing flexible compliance, the eligibility of out-of-state generation and the use of renewable energy credits ("REC"). PG&E's 2006 LTPP considers Commission directives regarding RPS, as well as SB 107.

h. California Solar Initiative

In January 2006, the Commission, in partnership with the CEC, issued a decision creating the California Solar Initiative ("CSI"), an 11-year $3.2 billion incentive program with the goal of installing 3,000 MW of new solar facilities on homes and businesses in California.[53] The Commission initiated a rulemaking to develop program rules and policies.[54] Phase 1 of the rulemaking addressed the incentives intended to be paid as a part of the program. The Commission issued a decision in Phase 1 on August 25, 2006, but recognized that recent legislation may affect the program.[55] In particular, SB 1, signed into law on August 21, 2006, establishes certain criteria for incentive eligibility and reduces the amount of incentives. The parties and Administrative Law Judge ("ALJ") in R.06-03-004 are currently briefing the effect of SB 1 on the CSI program. PG&E's 2006 LTPP considers the effect of the CSI program on long-term procurement.

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[51] R.06-02-012.

[52] R.06-05-027.

[53] D.06-01-024.

[54] R.06-03-004.

[55] D.06-08-028.

i. Energy Action Plan II's Goal of 33% Renewables by 2020

In the EAP II, the Commission indicated that it wanted to identify the steps necessary to achieve the 2010 target of 20% renewables, "as well as higher goals beyond 2010, such as Governor Schwarzenegger's proposed goal of 33% of electricity sales by 2020."[56] PG&E has been working aggressively to achieve the more immediate goal of 20% renewables by 2010, which is now mandated by SB 107. PG&E intends to continue to procure renewable power after 2010, and will direct its renewables procurement efforts to achieve Commission and legislative directives for the future. In its recommended plan, PG&E proposes procuring beyond the 20% target in 2010, subject to market availability. PG&E believes any specific expanded targets, beyond the 20% goal, would be premature until policy goals concerning GHG emission standards are clarified and a detailed feasibility analysis can be conducted. Volume 1, Section VI.C.2 provides information as to the potential cost of implementing a path to achieve the 33% goal by 2020, and Volume 2, Section I.B.5 describes the impact of proceeding with this goal.

4. The Scope of PG&E's 2006 Long-Term Procurement Plan

a. Duration of PG&E's 2006 Long-Term Procurement Plan

PG&E's 2006 LTPP addresses procurement that occurs during the 2007-2016 time period. However, some aspects of the procurement plan cover a longer time period. For example, after including preferred resources, PG&E is proposing procuring 2,300 MW in new dispatchable and operationally flexible resources to be available for operation beginning in 2011. These resources will be procured through a Request for Offer ("RFO") for long-term contracts. Although delivery from these new resources will commence in the 2007-2016 time period, deliveries will continue well beyond 2016. Moreover, to the extent PG&E selects a contract offered in a Long-Term Request for Offers ("LTRFO") that ultimately results in utility ownership, such as the contracts for Humboldt and Colusa facilities executed in March and April 2006, these facilities provide actual deliveries over an even longer planning horizon.

PG&E is also requesting "rolling" authority to enter into short-term and medium-term (*i.e.*, up to five years) procurement contracts. PG&E's authority to

[56] EAP II at 8.

enter into transactions five years or less would essentially "roll forward" until the next procurement plan is approved by the Commission. For example, assuming the 2006 LTPP is approved on June 1, 2007, PG&E could enter into a procurement contract for five years or less at any point between June 1, 2007 and approval of PG&E's next LTPP.

Finally, in addition to short-term and long-term electric procurement authority, PG&E is also requesting authority to procure natural gas supplies and related services for electric production and nuclear fuel for nuclear generation, as well as gas and electric hedging authority. The specific duration of the natural gas supply authority is described in Volume 1, Section III.C.1, the nuclear fuel procurement authority in Volume 1, Section III.C.2, and the electric and gas hedging authority in Volume 1, Section III.B.1.

b. Overview of PG&E's Planning Approach and Procurement Processes

The planning approach that PG&E used in developing its 2006 LTPP was intended to address the numerous uncertainties that arise in long-term energy planning. In developing its planning framework, PG&E considered the plans of PacifiCorp and Puget Sound, which the *Assigned Commissioner Ruling* issued December 2, 2005 mentioned as examples of integrated resource planning.[57] Following these examples, PG&E developed an analytical approach that formulates alternative candidate plans and uses a number of scenarios to test the performance of the candidate plans. PG&E then selected a recommended plan. As explained in more detail in Volume 1, Section VI, the recommended plan is a robust plan, and outperforms the other candidate plans under most scenarios based on metrics that follow the State Loading Order and least-cost, best-fit principles.

PG&E's analytical planning framework is composed of three main elements: scenarios, candidate plans and metrics. The scenarios are combinations of uncertainties affecting PG&E's procurement activities. PG&E classifies uncertainties into three categories. The first category is short-term cyclical uncertainties, typically represented by assigning probabilities to different outcomes or effects. The other two categories, long-term structural uncertainties and commercial uncertainties,

[57] *Assigned Commissioner's Ruling Regarding Next Steps In Procurement Proceeding*, issued December 2, 2005 in R.04-04-003 at 9, n. 5.

represent different states of the world which are out of PG&E's control. The candidate plans are alternative combinations of procurement actions that PG&E could pursue, including demand-side, supply–side and transmission actions. Finally, metrics are measures used to determine feasibility and performance of the candidate plans under each scenario. PG&E's planning framework is described in more detail in Volume 1, Sections IV.D and IV.H.

PG&E will implement the recommended plan through a number of procurement activities. First, PG&E is actively involved in demand-side programs consistent with EAP II and the State Loading Order. PG&E's energy efficiency, demand response and distributed generation programs are included in the recommended plan and effectively reduce procurement need.

Second, PG&E is aggressively pursuing renewable resources, consistent with EAP II and the Commission's RPS decisions.

Third, PG&E uses its short-term procurement authority for contracts that are five years or less in duration. These contracts allow PG&E the flexibility to purchase energy and other products to meet changing needs.

Fourth, PG&E is proposing to procure 2,300 MW of new, long-term dispatchable and operationally flexible resources. PG&E intends to procure this additional generation through RFOs which include Procurement Review Group ("PRG") review and the use of an Independent Evaluator ("IE").

Fifth, PG&E is proposing procurement plans for the fuel used to generate electricity, including natural gas and nuclear fuel.

Finally, PG&E is proposing procurement of natural gas pipeline transportation and storage to manage the physical needs of its electric portfolio, and hedging for electric and gas price risk.

C. Utility Service Profile

PG&E's service territory covers 70,000 square miles in northern California extending from the California-Oregon border to the Tehachapi Mountains at the southern end of the San Joaquin Valley. PG&E provides electric service to approximately 5.1 million customers in 47 out of 58 counties in California. Most of the PG&E Service Area has a Mediterranean-like climate, with rainy winters and warm dry summers. At coastal locations the influence of the ocean generally moderates temperature extremes, creating mild winters and relatively cool summers. The cool California Current offshore, enhanced by upwelling of cold sub-surface waters, often creates summer fog and cool temperatures near the coast. Further inland, the climate becomes more continental with colder winters and markedly hotter summers. The higher mountain areas of the PG&E Service Area, including the Sierra Nevada, have a mountain climate with snow in winter and mild to moderate heat in summer. The cold ocean waters at the coast and the topographic features inland create a seasonal temperature gradient between the immediate coast and the inland valleys, as shown in Table Vol. 1, IIC-1, below.

TABLE VOL. 1, IIC-1
PACIFIC GAS AND ELECTRIC COMPANY
AVERAGE MAXIMUM AND MINIMUM DAILY TEMPERATURES (°F), JANUARY AND JULY

Line No.	Region	City	January Max	January Min	July Max	July Min
1	Coast	Eureka	55	42	62	52
2		San Francisco	56	43	72	55
3		Morro Bay	62	42	66	52
4	Coastal Valley	Santa Rosa	57	37	83	51
5		Fairfield	55	38	89	56
6		Livermore	57	36	90	54
7		San Jose	59	42	83	58
8		San Luis Obispo	64	42	79	53
9	Inland Valley	Redding	55	36	98	65
10		Stockton	54	38	94	61
11		Fresno	55	39	98	61

Period of Record, 1971-2000. Source Western Region Climate Center.

As illustrated by the above table, the PG&E service territory is extremely diverse with respect not only to its geography, but also with respect to its climatology.

1. PG&E's Customer Demand

PG&E's electric customer base is made up of approximately 4.5 million residential customers, 550,000 small and medium-sized commercial customers, 80,000 agricultural customers and 1,250 industrial customers. More than 99% of customers in the residential, small commercial and agricultural classes receive PG&E utility procurement services. PG&E currently provides procurement services for approximately 95% of large commercial and 80% of industrial customers within its service territory. The remaining customers are served by a variety of non-utility electric service providers under direct access tariffs.

PG&E anticipates adding approximately 85,000 new electric customers per year over the next several years. Of these new customers, approximately 75,000 will be new residential customers, with the remainder being new small and medium commercial customers. The strongest expected growth in the residential sector continues to be centered in the San Joaquin Valley and Sierra Foothills regions. This presents a real challenge for PG&E procurement planning since these areas have high summer temperatures and the air conditioning saturation rates in these areas tend to be very high. The 2004 Residential Appliance Survey conducted by the CEC and the IOUs indicates that 8 out of 10 new homes are equipped with central air conditioning. This is roughly double the air conditioning saturation rate of existing homes in the PG&E service territory. [58]

PG&E's non-residential customers represent a wide range of business types and end-uses. No one business type or end-use dominates non-residential electric consumption in the PG&E service territory. Going forward, PG&E's expectation is that the trend in the northern California economy away from its traditional manufacturing and agricultural base and towards a services based economy will continue. This will result in continuing growth in electric consumption in the small and medium commercial market segments and stagnant to declining growth in the industrial and agricultural market segments.

For the past two decades, PG&E has experienced peak load growth, on average, of approximately 2% per year. Looking forward, PG&E expects that, consistent with EAP II, peak load growth will be somewhat lower than its historic mean due to increasing emphasis on customer energy efficiency through both utility-sponsored programs and statewide building and construction standards, as well as incentives to promote market acceptance of small scale self-generation technologies such as the California Solar Initiative.

2. PG&E's Transmission System

PG&E's electric transmission system consists of approximately 18,500 miles of transmission line and cable with nominal voltages of 500 kilovolts ("kV"), 230 kV, 115 kV, 70 kV and 60 kV. The 500 kV and 230 kV lines are often referred to as the

[58] California Statewide Appliance Saturation Study – Final Report – Executive Summary, Publication Number 400-04-009, June 2004, page 23.

"high-voltage" transmission facilities, while the lower voltage facilities are referred to as the "low-voltage" transmission facilities and sometimes as "sub-transmission."

PG&E's high voltage 230 kV transmission lines run north to south along both sides of the Central Valley and extend into the San Francisco Bay Area. PG&E's 500 kV facilities, which are an integral part of the high-voltage transmission system serving the Western United States and Canada, are integrated with PG&E's 230 kV facilities to provide the ability to exchange large blocks of power with the Pacific Northwest and Desert Southwest areas. This characteristic of having large amounts of regional exchanges moving through the PG&E system in either direction results in varying patterns of demand and usage during different times of year or day.

PG&E's high-voltage facilities are integrated with its low-voltage facilities (or sub-transmission) operating at 115 kV, 70 kV and 60 kV to serve wholesale and end-use electric customers. These lower voltage facilities are generally lower capacity than the high-voltage facilities and primarily serve to integrate local loads and resources into the transmission system. PG&E's high-voltage and low-voltage facilities are operated in parallel, as a grid, allowing greater reliability and improved power transfer capability of the whole system.

D. Lessons Learned Since Resuming Procurement January 1, 2003

1. Lessons Learned in Energy Procurement

PG&E resumed electric procurement on January 1, 2003. This resumption has required PG&E to construct a procurement organization suitable for the market environment that has emerged after industry restructuring and the energy crisis. PG&E now procures electric supplies through a combination of short-, medium- and long-term transactions. Since January 1, 2003, PG&E has procured energy services and products under authority granted by D.02-10-062, D.02-12-074, D.03-06-076, D.03-08-066, D.03-12-062, D.04-01-050 and D.04-12-048. PG&E has obtained these products and services in a variety of ways, including by issuing RPS and non-RPS RFOs, Request for Bids ("RFB"), negotiating bilateral agreements, and negotiating renewable bilateral agreements. The table below summarizes procurement transactions entered into between January 1, 2003 and June 30, 2006, under authority granted by the Commission.

TABLE VOL. 1, IID-1
PACIFIC GAS AND ELECTRIC COMPANY
JANUARY 1, 2003 – JULY 30, 2006 COMMISSION PRE-APPROVED
ELECTRIC PROCUREMENT TRANSACTIONS[59]

Line No.		Volume (GWhs)	Number of Transactions	Number of RFOs Issued	Cost ($ Million) Capacity	Cost ($ Million) Energy
1	Short Term (up to 1 year)	935	104	9	36	54
2	Medium Term (1-5 years)	2,469	17	1	258	35
3	Long Term (5 years and >)	1,030	4	1	0	66

PG&E has used competitive procurement solicitations to procure short- and medium-term capacity and energy products, energy-only products, options, and tolling agreements. For longer-term supplies, PG&E conducts annual RFOs for renewable generation and recently received Commission approval for 2,250 megawatt (“MW”) of new peaking and shaping resources selected through its 2004 LTRFO.

PG&E has learned a number of important lessons since it resumed procurement in January 2003. First, the market has responded well to PG&E’s competitive solicitations. In procurement solicitations, the response has been robust, making for a competitive process which benefits customers.

The results of PG&E’s LTRFO, with its mix of Purchase Power Agreements (“PPA”)and Purchase and Sale Agreements (“PSA”), mix of technologies (combustion turbines, reciprocating engines and combined cycle plants) in response to PG&E’s request for specific operating attributes and diversity of locations, demonstrate the benefits of head-to-head competition of utility-owned and purchased generation.

Second, the Commission’s support of PG&E’s procurement efforts is essential. Regulatory support has been crucial as PG&E has emerged from bankruptcy and resumed procurement following the energy crisis. The Commission has followed the requirements of AB 57 in approving PG&E’s procurement plans and establishing up-front standards for procurement and cost recovery. The Commission-approved planning process has enabled PG&E to meet the objectives of AB 57 and the EAP II, and to procure electric and gas supplies at reasonable costs for customers.

[59] This table does not include: (1) spot purchases and sales up to balance of the month; (2) DWR contracts; (3) QF, Irrigation District and Water Agency contracts (pre-2003 contracts); (4) PG&E-owned generation; and (5) contracts executed in the 2004 LTRFO.

Third, the PRG has brought benefits to the procurement process by providing PG&E with valuable review and insights on all aspects of PG&E's supply-side procurement. PG&E finds regular consultation with the PRG improves all parties' understanding of the issues, enhances communication between the parties, and enhances the ultimate procurement decision-making process. Due to PG&E's ongoing dialogue with the PRG, PRG members have the opportunity to learn about challenges the utility faces in real time, rather than hearing about them after a decision has been made and submitted for Commission approval. PG&E also benefits from the PRG process because PRG members can advise PG&E of potentially contentious issues prior to PG&E executing a transaction. In addition to the PRG, the IE has also provided beneficial review of PG&E's procurement processes and competitive procurement results. In general, PG&E and members of the PRG who subsequently participated in the 2004 LTRFO view the IE's involvement as beneficial both in terms of ensuring a fair process, as well as in the actual selection of projects.

Fourth, in conducting procurement, there is a need to consider uncertainty in the planning and commercial processes. A good example of planning uncertainty occurred during the summer 2006 heat storm, when California experienced levels of demand that were not expected for another five years. Another example is the uncertainty PG&E faces regarding the actual development of proposed projects. In the 2004 LTRFO, PG&E procured additional megawatts in part because of the uncertainty that one or more projects may not come to fruition. In that proceeding, both PG&E and the IE concluded that it was better to procure more capacity than to run the risk of reliability problems and price increases should projects be delayed or cancelled.

Fifth, while competitive procurement has benefits, there can also be benefits from bilateral and unique transactions. A good example is PG&E's acquisition of the Contra Costa 8 facility, recently approved by the Commission. PG&E will acquire this partially completed facility at no cost, and will complete its construction and operate it. PG&E's customers will therefore realize the benefits of a new 530 MW facility at a below-market price. The Commission should continue to support such opportunities if they arise.

Sixth, the Commission's current rules regarding disclosure of information may harm the commercial process and may lead to higher prices for customers. Winning bidders in PG&E's competitive procurement solicitations often do not have key elements of their projects completely secured when PG&E is required to file for approval and disclose these projects' identities. Such disclosure can put the projects at a disadvantage if they do not have aspects such as site control or supplier contracts completed.

Seventh, requirements regarding PRG consultation must be modified to address changes in the market. The Commission currently requires consultation with the PRG for all transactions that either: (1) begin deliveries more than 3 months in the future, or (2) have a term greater than 3 months.[60] This requirement has achieved the objective of communicating with the PRG and soliciting valuable feedback. However, recent increases in market volatility have necessitated more frequent hedging. Improved liquidity in the forward (3 to 12 months) markets presents opportunities to hedge the market volatility, but PG&E is unable to do so efficiently with the current consultation requirements. Changing the 3-month threshold requirements to consult with the PRG to thresholds greater than six months would allow PG&E to adapt to market developments and transact in a more efficient manner. This proposed change is discussed in Volume 2, Section II.A.1.

2. Lessons Learned in Renewables Procurement

PG&E has now had several years of experience in procuring renewable resources, including three annual RPS solicitations and bilateral negotiations. PG&E has learned a number of lessons during this process, which have been identified in the on-going RPS proceedings (R.06-05-027) and in annual RPS Procurement Plan filings, such as the 2007 Procurement Plan that PG&E filed on September 26, 2006 in R.06-05-027. PG&E provides a summary of these lessons learned below.

First, PG&E's experience with the Supplemental Energy Payments ("SEPs") is that developers cannot obtain financing for this revenue stream due to the uncertainty of its availability. Also, the SEP application process is slow, burdensome, inefficient and needs reform.

Second, the Time-of-Delivery factors, used to differentiate a project's payments between time periods and allow the utility to value the project power output in each time period should be updated based on recent forward market prices for natural gas and wholesale power.

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[60] D.03-12-062; D.04-12-048 Conclusion of Law No. 15.

Third, RPS PPAs should contain terms that entitle PG&E to curtail a facility's output, consistent with the CAISO tariff, transmission safety standards, and maintenance requirements.

Fourth, collateral requirements should be reduced during project development for projects with lower capacity factors, while still requiring adequate collateral to encourage performance under those projects' contracts.

Fifth, for projects located outside of the CAISO-controlled grid, bidders should provide two separate prices: one price based on delivery onto the CAISO-controlled grid and one price based on delivery outside the CAISO-controlled grid.

Sixth, there are certain administrative changes that will improve the RPS solicitation process. PG&E has identified these administrative changes in R.06-05-027 and its annual RPS Procurement Plan filings.

Seventh, because of the growing importance of transmission access and interconnection in assuring compliance with the RPS standards, PG&E will need to take a number of steps to consider transmission upgrades, renewable project locations, and alternative commercial arrangements.

Finally, PG&E's experience with repowering of renewables projects is that it is unlikely to materialize due to local permitting constraints.

Many of these lessons are described in more detail in Volume 1, Section IV.C.2. PG&E is optimistic that the lessons it has learned and identified in the ongoing RPS proceedings will result in refinements to and modifications of the RPS program to make it more efficient and effective.

3. Lessons Learned in Electric and Gas Hedging

Since PG&E resumed electric procurement in 2003, the exposure of its electric portfolio to price risk has grown dramatically, driven in large part by the gas component of the portfolio. In response, PG&E developed a formal multiple year gas hedging program to manage this risk, supplementing the hedging authority granted under PG&E's 2003 and 2004 STPPs. This program is a framework for reducing exposure to gas price risk by trading a variety of financial gas products in the financial markets. In addition, PG&E has already implemented a shorter-term program for electricity hedging to reduce the exposure to market risks. The framework for these hedging programs, as well as proposed program modifications, are discussed in Volume I, Section III.B.1.

PG&E has several "lessons learned" with respect to electric and gas hedging. These lessons came from PG&E's early hedging activities under its 2003 and 2004 STPP, as enhanced by its Electric Portfolio Gas Hedging Plan ("GHP")and its succeeding updates, and market activity over the past three and a half years.

First, hedging activity, especially hedging the gas component, has a significant impact on To-expiration Value-at-Risk ("TeVaR"), and thus, overall portfolio risk. PG&E has successfully reduced TeVaR with its gas hedging program. However, gas and electric hedging cannot guarantee that PG&E's electric portfolio TeVaR will remain below the Commission-approved Consumer Risk Tolerance ("CRT") of $0.01/kilowatt-hour ("kWh"). At times, PG&E has found that even if electric and gas positions were 100% forward hedged, TeVaR could still exceed the CRT due to other portfolio risks such as load and hydro risk uncertainty.

Second, during implementation of the gas hedging program, market timing risk can be reduced by spreading trading over a longer period of time. For example, in 2005, PG&E benefited from beginning implementation of its gas hedging program in the spring, long before Hurricane Katrina impacted the gas market. This desirable characteristic is built into the hedging operating targets.

Finally, it is most effective to manage hedging of the electric portfolio electricity and gas components in an integrated manner, using a consistent set of operating targets over a common forward period. This is discussed in detail in Volume I, Sections III.B.1 and III.B.3.

E. Changes Since Previous Procurement Plans

In addition to incorporating PG&E's existing STPP authority and 2004 LTPP authority, PG&E's 2006 LTPP incorporates the following major changes relative to prior long-term procurement plans:

- The 2006 LTPP uses an analytical framework based on the past resource plans of PacifiCorp and Puget Sound. PG&E's planning approach uses a number of scenarios to test the performance of three candidate procurement plans based on selected metrics. Volume 1, Section IV.A describes PG&E's analytical approach.

- The 2006 LTPP includes larger amounts of preferred resources, and associated transmission, than any previous PG&E procurement plan.

Volume 1, Section V.B–V.E describes in detail PG&E's plans to develop preferred resources.

- The 2006 LTPP also estimates and asks for authority to procure 2,300 MW of new dispatchable and operationally flexible resources to come on line starting in 2011. These resources are needed to meet the needs of bundled and unbundled customers in PG&E's service area. Volume 1, Section IV.E provides estimates of residual capacity resource needs for bundled and unbundled customers in PG&E's service area. Volume 1, Section IV.H provides estimates of the amounts and types of power products that are needed to meet the energy and capacity needs of PG&E's bundled customers.

- In Volume 1, Section V.H, PG&E also estimates its Local RA needs for the 2007-2016 planning horizon.

- The 2006 LTPP also proposes a long-term hedging plan, gas supply plan, and a nuclear fuel supply plan. PG&E's support for the requested authority for these plans is provided in Volume 1, Sections III.B and III.C and Volume 2, Sections III.A, IV.B and IV.C.

F. Decisions Pending at Commission Related to Procurement

The 2006 LTPP integrates policy developments in procurement-related dockets and implements procurement-related orders and guidelines issued by the Commission. There are a number of pending procurement-related decisions at the Commission that may affect PG&E's procurement plan, including:

- **LTRFO A.06-04-012**. The LTRFO application was filed on April 11, 2006, to approve seven long-term commitments to procure 2,250 MW of new generation resources. A decision approving PG&E's request was issued on November 30, 2006. In its 2006 LTPP, PG&E assumed that the LTRFO application is approved.

- **Demand Response.** On August 30, 2006, PG&E filed a *Proposal for Enhancements to Demand Response Programs* in response to August 9, 2006 and August 22, 2006 Assigned Commissioner Rulings ("ACR") in A.05-06-066. The proposal would have added 235 MW of demand response in 2007 and 260 MW in 2008. On November 30, 2006, the Commission issued a decision adopting some, but not all, of PG&E's proposed enhancements.

- **Energy Efficiency**. The 2006 LTPP captures the Customer Energy Efficiency ("CEE") 2006-2008 savings recently approved by D.05-09-043 and PG&E's subsequent Compliance Filing in Energy Efficiency R.01-08-028. The 2006 LTPP also identifies uncertainties associated with post-2008 CEE targets via scenarios (see Volume 1, Sections IV.C and V.B for detailed discussion). R.06-04-010 is expected to address the Commission's CEE targets beyond 2008.

- **Distributed Generation.** The 2006 LTPP captures the policy developments and PG&E efforts in the Distributed Generation proceeding (R.04-03-017) by incorporating the range of timing and availability of solar generation and availability of combined heat and power in the LTPP scenarios. Supply assumptions reflect D.06-01-024, which adopted policies and funding for the California Solar Initiative (*see* Volume 1, Section IV.C.1.c). In addition, PG&E expects a decision in December 2006 or early 2007 that would revise the 2007-2011 targets for solar generation as a result of SB 1.

- **Greenhouse Gas.** PG&E has evaluated the environmental effect of the candidate plans and provides GHG emissions forecasts of candidate resource plans in Volume 1, Sections VI.B.5. SB 1368, the recently passed Emissions Performance Standard ("EPS") legislation, mandates that the Commission implement an EPS by February 1, 2007. Prior to the passage of SB 1368 in September 2006, the Commission initiated a GHG Order Instituting Rulemaking (R.06-04-009). The GHG OIR will incorporate the mandates of SB 1368 as well as address issues which SB 1368 may not have addressed. A final decision in Phase 1 of the proceeding is expected in January 2007 and is intended to create model regulations for AB 32 implementation for all LSEs. The EPS standard adopted by the Commission will likely apply to baseload facilities entering into long-term contracts. Phase 2 of the proceeding is intended to address implementation issues associated with the load based GHG emissions cap adopted in D.06-02-032 and is mandated to be completed within two years of the initiation of the second phase. It is expected that

Phase 2 will be closely coordinated with the activities for adopting AB 32, the recently passed bill instituting a formal cap and trade system by 2012. PG&E discusses in greater detail how the proposed GHG emissions portfolio standard will affect procurement practices in Volume 2, Section I.B.2. The adoption of the standard will affect PG&E's selection criteria for any new long-term generation commitments.

- **Resource Adequacy.** The Commission has effectively completed Phase 1 of the RA proceeding (R.05-12-013) by adopting local RA standards and associated implementation decisions. D.06-06-064 established Local RA standards for 2007 and D.06-07-031 clarified and refined outstanding RA issues. For the next phase of the RA proceeding, an ALJ Ruling issued on August 18, 2006 identified potential issues to be addressed in four possible future decisions proposed for the period between January 2007 and March 2008. The ALJ has not yet issued a Scoping Memo for Phase 2. The following Phase 2 issues could have a significant impact on procurement: (1) RA requirements for small and multi-jurisdictional utilities to level the playing field for all jurisdictional entities; (2) the backstop mechanism for existing and/or new capacity as well as the opt-out provision to allow exemption of resource sufficient LSEs from the cost allocation process adopted as part of D.06-07-029; (3) changes to the local RA program; (4) basic elements of a centralized capacity market or its alternatives, and the need for multi-year forward commitments; and (5) zonal RA.

- **Transmission.** The 2006 LTPP implements the order in D.04-12-048 to integrate generation and transmission planning. PG&E's recommended plan accounts for various uncertainties including transmission of power from out-of-state renewable projects. The Commission initiated the Transmission for Renewables Order Instituting Investigation ("OII"), I.05-09-005, to investigate changes to the transmission planning, permitting, and cost recovery processes, as it relates to renewables. PG&E is expecting a ruling from the ALJ outlining the next steps in this proceeding.

- **Confidentiality.** The 2006 LTPP is prepared in accordance with confidentiality protections afforded by D.06-06-066 in Confidentiality

Rulemaking (R.05-06-040). A decision on the definition of a market participant is expected in Phase 2 of that proceeding.

- **MRTU Implementation.** The CAISO plans to implement its MRTU in November 2007. Implementation details are still evolving. PG&E describes some of the features of MRTU in Volume 2, Section I.B.3.

- **Contra Costa 8 Advice Letter.** PG&E recently filed Advice Letter 2928-E with the Commission requesting approval of an increase in the capital cost associated with increased capital costs and resulting revenue requirements for dry-cooling at the CC8 facility. This advice letter is still pending before the Commission. For purposes of the 2006 LTPP, PG&E assumes the advice letter is approved and that it proceeds with construction of the CC8 facility.

In preparing the 2006 LTPP, PG&E has necessarily made assumptions regarding the outcome of certain proceedings. If these assumptions prove incorrect because of actual policy and market developments, PG&E reserves the right to modify or change its proposed 2006 LTPP via an advice letter filing updating planning assumptions and/or procurement implementation authority.

PACIFIC GAS AND ELECTRIC COMPANY

VOLUME 1 – 2006 LONG-TERM PROCUREMENT PLAN

SECTION III – PROCUREMENT IMPLEMENTATION PLAN

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III. PROCUREMENT IMPLEMENTATION PLAN

A. Procurement Processes

1. PG&E's Energy Procurement Organization

Pacific Gas and Electric Company's ("PG&E") Energy Procurement ("EP") organization plans for and acquires resources to ensure an adequate and reliable energy supply. EP has a number of procurement objectives, including assembling a portfolio of reliable and operationally flexible resources, supporting the development of environmentally preferred resources, and managing customer costs. The organization is responsible for both front-office functions associated with planning, procuring, scheduling, and dispatching resources, and back-office functions associated with ensuring accurate payments to the California Independent System Operator ("CAISO") and other power suppliers. EP is comprised of the following departments:

- Energy Policy, Planning & Analysis ("EPPA");
- Energy Supply;
- Energy Contract Management and Settlements; and
- Market Redesign and Technology Upgrade ("MRTU") Implementation and Federal Energy Regulatory Commission ("FERC") Refund.

The following section discusses the primary goals and responsibilities of each of the departments listed above. In addition, PG&E describes how its EP organization complies with California Public Utilities Commission ("Commission") Standard of Conduct No. 2.[1]

a. Energy Policy, Planning & Analysis

EPPA strives to meet the EP organization objectives through electric and gas resource planning that truly integrates demand-side and supply-side resource alternatives, and transmission and generation alternatives. EPPA analyzes regional supply-demand balances, the composition of potential PG&E portfolios, and the value of incremental resources to PG&E customers and regional supply. EPPA performs these analyses using financial, economic, and engineering methodologies and tools. EPPA analyzes current and potential market structures and policy initiatives, such as the State Loading Order, capacity markets and resource adequacy, and considers how these developments impact PG&E's procurement.

b. Energy Supply

Energy Supply is responsible for all commercial transaction activities through competitive solicitations, bilateral negotiations and energy markets, including the development and execution of electric and fuels procurement strategies for short-term, medium-term, and long-term transactions, which will meet PG&E's customers' forecasted energy needs. The commercial transactions also include the procurement of renewable supplies to meet PG&E's Renewable Portfolio Standard requirements ("RPS"). Energy Supply's responsibilities also include: (1) the management, optimization, and scheduling of PG&E's resources and contracts; (2) PG&E's trading in the energy markets; and (3) the natural gas procurement and hedging activities for PG&E's resources, power purchase agreements and assigned California Department of Water Resources ("DWR") contracts.

Energy Supply also purchases natural gas supplies and transportation capacity to meet PG&E's bundled core gas customer demands. The gas procurement function relates generally to the process of acquiring gas supplies (*e.g.*, the gas commodity) and managing transmission and storage capacity for core gas customers.

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[1] The Commission originally adopted Standards of Conduct for procurement in Decision ("D.") 02-10-062. These standards have subsequently been modified. *See* D.02-12-074, Order Paragraph 24 (modifying standards); D.03-06-067, Ordering Paragraph 3 (modifying standards and eliminating Standard Nos. 6-7); and D.03-06-076, Ordering Paragraph 6 (clarifying that "Standard of Conduct 1 does not preclude anonymous transactions conducted through the ISO or through brokers and exchanges."). PG&E also received a waiver from Standard of Conduct 1 for certain gas transportation transactions in D.04-06-003.

c. Energy Contract Management & Settlements

The Energy Contract Management & Settlements department is responsible for the preparation of regulatory filings, and implementation of standard reporting and documentation related to energy procurement and settlements activities. The department monitors compliance with risk control and Sarbanes-Oxley ("SOX") requirements, and performs contract management, settlements and financial reporting related to energy procurement, including bilateral purchases and sales, Fuel, Qualifying Facility ("QF"), Irrigation District ("ID"), Reliability Must-Run ("RMR"), and DWR allocated contracts, as well as CAISO market settlements. This work includes contract monitoring, validating calculations and data, preparing invoices, processing payments, and duties related to PG&E's role as transmission owner and CAISO scheduling coordinator for both retail and existing transmission contract customers.

d. MRTU Implementation and FERC Refund

The CAISO's MRTU initiative significantly changes the electric markets administered by the CAISO and represents the largest change to the California wholesale energy market since electric restructuring began in 1998. It is scheduled to become effective November 2007. The MRTU Implementation and FERC Refund Department works with internal and external stakeholders to translate complex market designs into the needed systems and software and assure they perform as intended. In addition, on behalf of PG&E's customers, this department continues its efforts to obtain refunds for electricity overcharges during the 2000-2001 California Energy Crisis. The department provides support and expert analysis in the FERC Refund proceedings, negotiations with suppliers, and bankruptcy issues related to generator claims filed in PG&E's bankruptcy.

e. Compliance With Commission Standard of Conduct No. 2

The employees in PG&E's EP organization manage a substantial portfolio of resources to ensure PG&E acquires a reliable, environmentally preferred, and cost-effective portfolio of supply-side and demand-side resources for its customers. The EP employees, as well as the employees throughout PG&E, comply with the Commission's Standard of Conduct No. 2, to the extent it is applicable. Standard of Conduct No. 2 provides:

Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurements process that:

1) Identifies trade secrets and other confidential information;

2) Specifies procedures for ensuring that such information retains its trade secret and/or confidential status (*e.g.*, limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.);

3) Discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges;

4) Discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; and

5) Requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances (*e.g.*, where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer). All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility.

To ensure compliance, on the first day of employment with PG&E, employees are given an employee policy handbook on "Standards for Personal Conduct and Business Decisions, Code of Conduct for Employees" which can be found at the following link: http://www.pge-corp.com/aboutus/pdfs/EmployeePolicyHandbook2004.pdf. The handbook includes discussions regarding proprietary information and antitrust law. Upon completion of their review, employees are required to sign a summary form acknowledging receipt of the booklet and that they have reviewed and understood the material. In addition, PG&E employees are required to complete a Compliance and Ethics training course on an annual basis, a description of which can be found at the following link: http://www.pge-corp.com/aboutus/ethics_compliance. The annual Compliance and

Ethics training includes a review of various parts of the Code of Conduct for Employees handbook.

2. Overview of PG&E's Procurement Process

PG&E's procurement process involves three phases: planning, competitive procurement and economic dispatch.

a. Planning

In the planning phase, PG&E identifies the resource needs of its customers and complies with the State Loading Order, Energy Action Plan II ("EAP II") and other Commission and legislative directives.[2] In analyzing its needs, PG&E identifies specific power products. These power products include energy products (baseload, shaping, and peaking), capacity products to meet Resource Adequacy ("RA") requirements, and various ancillary services products, including spinning, non-spinning, regulation, and black-start capability. The following table summarizes some of the power products available from various resource alternatives, which PG&E identifies in the planning phase.

[2] PG&E also looks at the reliability need for its entire service area, as described in Volume 1, Section IV.E.

TABLE VOL. 1, IIIA-1
PACIFIC GAS AND ELECTRIC COMPANY
POWER PRODUCTS AVAILABLE FROM RESOURCE ALTERNATIVES

		Energy Products					Ancillary Service Products					
Line No.	Resource Types	Base-load	Inter-mittent Energy	Shaping	Peaking	Capacity (RA)	Black Start	Quick Start (10 min.)	Emer-gency (30 min-3 hr)	Regu-lation	Spinning	Non-Spinning
1	Preferred Resources											
2	Energy Efficiency	X				X						
3	Demand Response				X	X			X			X
4	Renewable-Intermittent		X			X						
5	Renewable-Baseload	X				X						
6	Distributed Generation-Non PV	X				X						
7	Conventional Resources											
8	Combustion Turbine				X	X	X	X	X	X	X	X
9	Reciprocating Engines				X	X	X	X	X	X	X	X
10	Combined Cycle			X		X			X	X	X	X
11	Base (*e.g.*, coal, nuclear)	X				X						

After identifying the amount and timing of its need, PG&E then prepares and files a procurement plan with the Commission, seeking authority to procure these products. Once the Commission approves a procurement plan, the procurement process shifts to the competitive procurement phase.

b. Competitive Procurement

PG&E implements its Commission-approved procurement plan through various processes, including solicitations, bilateral negotiations and participation in various markets. PG&E's procurement practices are described in detail in Volume 1, Section III.A.5, below. PG&E enters into short-term, medium-term and long-term contracts that result from the competitive procurement process. PG&E defines short-term contracts as contracts with a term of one year or less in duration; medium-term contracts as contracts with a term greater than one year but less than five years in duration; and long-term contracts as contracts with a term five years or greater in duration. Renewable contracts are an exception to this rule, with anything under 10 years in duration being short-term for this contract category.

c. Dispatch

Consistent with Commission decisions,[3] PG&E economically dispatches its portfolio subject to the contractual and operating limitations of the resources in the portfolio. In implementing least-cost dispatch, PG&E dispatches resources or purchases energy with the lowest incremental cost of providing energy, which includes the variable operating costs of its own resources or resources under its control and the market cost of generation.[4] PG&E uses incremental cost dispatch for all resources within its portfolio. This includes utility-owned generation, bilateral contracts, allocated DWR contracts, and resources available to PG&E from the marketplace.

Least cost dispatch includes market sales. When PG&E is "physically" or "economically" long, least-cost dispatch requires PG&E to undertake certain market sales. PG&E is "physically long" when must-take energy supply exceeds demand. During those periods, PG&E sells excess energy at market prices. Because PG&E is required to take or generate this energy in any event, the incremental cost of that energy is zero. PG&E is "economically long" when the incremental cost of dispatchable resources is less than the market price, even though PG&E has no need for the energy to serve its customers. Under these circumstances, the economically efficient dispatch decision is to use the dispatchable resource to generate power and market the surplus energy.

3. Description of Procurement Products

a. Electric Products

PG&E uses a variety of physical and financial electric products to meet its electric procurement needs. Table Vol. 1, IIIA-2 below provides product names, descriptions and information about PG&E's existing regulatory authority to procure these products, and includes new products related to MRTU.

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[3] The Commission's Standard of Conduct No. 4, adopted in D.02-10-062 and modified on in D.02-12-069, D.02-12-074, D.03-06-076, and D.05-01-054, requires PG&E to meet its electric load obligations in a least-cost manner. In addition, D.04-07-028 ordered that system reliability and deliverability of power be included as part of least-cost dispatch.

[4] Because the least-cost dispatch for hydro-electric resources takes into consideration the future value of water and the fact that because the amount of available water is limited, it may be more cost-effective to defer hydro-electric generation to higher value time periods.

TABLE VOL. 1, IIIA-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS

	Product	Description(a)	Prior Authorization
1	Ancillary Services	Products that are utilized by the control area operator to ensure electric system reliability, for example, those that are listed in control area operator tariffs, such as the CAISO.	D.02-10-062
2	Capacity (demand side)	The amount of power consumed by a customer, measured in megawatts (“MW”), that can be reduced upon request.	D.02-10-062
3	Capacity (purchase or sale)	The amount of power capable of being generated, measured in MW, that can be converted to energy upon request.	D.02-10-062
4	Contingent Forward	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
5	Electric Product Exchange	The buyer has an obligation to receive electric products and an obligation to return electric products as part of the same transaction. The transaction may also include an exchange of payments, in fixed or variable terms. Electric products include energy, capacity, and ancillary services.	AL 2615-E
6	Electricity Transmission Products	Purchase, sale, or allocation of transmission rights, products (e.g., LT-FTRs, CRRs, losses), or the use of locational spreads.	D.02-10-062 and revision requested to generalize transmission products. See Volume 2, Section I.B.3 – Impact of MRTU on Procurement Practices
7	Financial Call (or Put) Option	The right, but not the obligation, to buy (call) a forward electric contract on a specific date (expiration) at a fixed or indexed price (strike). The right to sell is a put option.	D.02-10-062
8	Financial Swap	An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps and basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.	D.02-10-062 AL 2615-E
9	Forward Energy (demand side)	Electric energy planned to be consumed by a customer, measured in megawatt-hour (“MWh”) that is agreed to be reduced for a specific period for a specified time in the future.	D.02-10-062
10	Forward Energy (purchase or sale)	Electric energy purchased or sold by a counterparty, measured in MWh that is agreed to be supplied or received for a specific period at a specific location for a specified time in the future.	D.02-10-062
11	Forward Spot (Day-Ahead & Hour-Ahead) purchase, sale, or exchange	Electric energy, capacity, ancillary services or transmission purchased or sold by a counterparty, or exchanged between counterparties measured in MW or MWh that is agreed to be supplied, received or exchanged for a specific period at a specific location in the Day-Ahead or Hour-Ahead markets.	D.02-10-062

TABLE VOL. 1, IIIA-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS
(CONTINUED)

	Product	Description(a)	Prior Authorization
12	Insurance (counterparty credit insurance, cross commodity hedges)	A method for managing payment or performance risk for a fee.	D.02-10-062
13	New York Mercantile Exchange ("NYMEX") Electricity Futures (purchase or sale)	Standardized forward energy contract traded on NYMEX. Futures may be physically or financially settled.	AL 2615-E
14	On-Site Energy or Capacity (self-generation on customer side of the meter)	The amount of power measured in MW or MWh that can be generated downstream of the customer's electric meter that can be used to offset the customer's load served by the electric service provider.	D.02-10-062
15	Peak for Off-Peak Exchange	Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied in an on-peak period in exchange for receiving an amount in an off-peak period. These transactions may also include an exchange of dollars.	D.02-10-062
16	Physical Call (or put) Option	The right, but not the obligation, to buy (call) physical electricity for delivery on a specific date at a fixed or indexed price (strike). The right to sell is a put option.	D.02-10-062
17	Real-Time (purchase or sale)	The amount of energy, measured in MWh supplied or received by the control area operator to balance an entity's load and supply.	D.02-10-062
18	Resource Adequacy Product	A capacity product intended to meet resource adequacy obligations.	AL 2615-E
19	Seasonal Exchange	Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied during one season or set of months in exchange for receiving an amount in another season or set of months. These transactions may also include an exchange of dollars.	D.02-10-062
20	Tolling Agreement	An agreement to provide (receive) gas in exchange for receiving (providing) electricity.	D.02-10-062, D.04-12-048
21	Counterparty Sleeves	An agreement by a counterparty to buy (sell) electricity from one counterparty and sell it to (buy it from) another counterparty.	D.03-12-062
22	Emissions Credits Futures or Forwards	Credits or allowances for emissions that can be bought or sold in order to comply with emissions limits.	D.03-12-062
23	Forecast Insurance	A method for managing load forecast (volume and shape) risk.	D.03-12-062
24	Firm Transmission Rights ("FTR") Locational Swaps	Over-the-counter basis swaps associated with Firm Transmission Rights. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	D.03-12-062
25	Non-Firm Transmission Rights ("Non-FTR") Locational Swaps	Over-the-counter basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	D.03-12-062

TABLE VOL. 1, IIIA-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS
(CONTINUED)

	Product	Description(a)	Prior Authorization
26	Weather Triggered Options	A method for managing temperature and other weather forecast risks.	D.03-12-062
27	CAISO Uplift Load Obligations	Obligations that are associated with bid cost recovery guarantees by the CAISO.	New transaction requested in Volume 2, Section I.B.3 – Impact of MRTU on Procurement Practices
28	Non-Discretionary Products Required by MRTU	MRTU products, which may be created by the CAISO during the finalization of MRTU and that would be *mandatory* in order to participate in MRTU.	New transaction requested in Volume 2, Section I.B.3 – Impact of MRTU on Procurement Practices

(a) With the exceptions of the CAISO Uplift Load Obligations and Non-Discretionary Products, all of the products described above are unchanged from the products approved in previous filings. Some of the descriptions differ in non-substantive ways from those included in previous filings. PG&E is updating these descriptions for purposes of the 2006 Long-Term Procurement Plan ("LTPP").

b. Gas Products

PG&E uses a variety of physical and financial gas products to support electric procurement. Physical gas products are used to support least-cost dispatch and reliability. Table Vol. 1, IIIA-3 below provides physical gas product names, descriptions and information about PG&E's existing regulatory authority to procure these products and includes a description for proposed new product – biomethane.

TABLE VOL. 1, IIIA-3
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PHYSICAL PRODUCTS

	Product	Description(a)	Prior Authorization
1	Natural Gas Purchases (physical supply)	Purchases/sales/exchanges of physical natural gas for terms of one month or longer.	D.02-10-062
2	Spot Natural Gas (physical supply)	Purchases/sales/exchanges of physical natural gas for terms less than one month.	D.02-10-062
3	Physical Options on Natural Gas Supply (purchase or sale)	The right, but not the obligation, to buy (call) physical gas for delivery on a particular date at a fixed or index price (strike). The right to sell is a put option.	D.02-10-062
4	Biomethane (purchase or sale)	Pipeline quality natural gas produced from renewable (non-fossil based) resources. May include renewable or environmental attributes.	New
5	Contingent Forward (purchase or sale)	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
6	Gas Storage (purchase or sale)	Includes firm and as-available storage inventory, injection and withdrawal. Also includes parking and borrowing services.	D.02-10-062
7	Gas Transportation (purchase or sale)	Interstate, Intrastate, and distribution gas transportation services. Includes firm, as-available and interruptible services.	D.02-10-062
8	Counterparty Sleeves	Facilitating a transaction with an un-contracted or non-creditworthy through a contracted, creditworthy counterparty.	D.02-10-062

(a) With the exception of Biomethane (purchase or sale), all of the products described above are unchanged from the products approved in previous filings. Some of the descriptions differ in non-substantive ways from those included in previous filings. PG&E is updating these descriptions for purposes of the 2006 LTPP.

Financial products are used to support gas hedging. Table Vol. 1, IIIA-4 below provides financial gas product names, descriptions and information about PG&E's existing regulatory authority to procure these products.

TABLE VOL. 1, IIIA-4
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS FINANCIAL PRODUCTS

	Product	Description(a)	Prior Authorization
1	Natural Gas Financial Swaps (purchase or sale)	Over-the-counter forward products including fixed-for-floating swaps, basis swaps and swing-swaps for gas. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	AL 2615-E D.02-10-062
2	Natural Gas Futures (purchase or sale)	Standardized forward contracts for gas that trade on an exchange. Futures may be physically or financially settled. Physically settled futures may be unwound by an offsetting trade, exchanged for a physical position, or held to physical delivery.	AL 2615-E
3	Financial Options (Call or Put) (purchase or sale)	The right, but not the obligation, to buy (call) a forward gas contract on gas on a particular date (expiration) at a particular price (strike). The right to sell is a put option. OTC-traded options settle in cash, whereas exchange traded (NYMEX) options must be exercised, which causes delivery of a futures position to the option holder. Options may be combined with other options or swaps to hedge a wide variety of positions.	D.02-10-062

(a) All of the products described above are unchanged from the products approved in previous filings. Some of the descriptions differ in non-substantive ways from those included in previous filings. PG&E is updating these descriptions for purposes of the 2006 LTPP.

The products presented in this section include those products PG&E is currently authorized to transact, as well as products that it knows may be required in the future. PG&E will request approval through advice letter filings of new products that arise from changed policies or market developments that are not covered by the above lists. Such products may be necessary to satisfy procurement needs arising from MRTU implementation, new legislation or other requirements such as the emergence of Renewable Energy Credit markets for compliance with the RPS Program.

4. Overview of Energy Product Markets

This section provides an overview of the markets available to PG&E to purchase the products described in Volume 1, Section III.A.3, above. PG&E's specific procurement practices are described in detail in Volume 1, Section III.A.5, which follows this section.

a. Exchanges

For electric and gas markets there are several types of transparent exchanges: Over-The-Counter electronic trading platforms such as the Intercontinental Exchange ("ICE"), NYMEX Clearport, NYMEX Globex, and the Natural Gas Exchange ("NGX"); and open outcry exchanges such as the NYMEX. The electronic platforms allow market participants to post bids and offers for specific gas and electric products. To complete a trade, a buyer must lift an offer or a seller must hit a bid. Once completed, the exchange confirms the transactions to both parties. NYMEX hosts open outcry trading for its natural gas futures contracts and natural gas options. Buyers and sellers transmit bids and offers to the trading pits through a Futures Commission Merchant ("FCM"). The trade is executed by the trader in the trading pit. The results of the trade are communicated back to the buyer or seller through the FCM.

For the electronic exchanges, buyers post bids to the system. If a seller hits the bid, the trade is completed. If a seller does not hit the bid, the buyer can adjust its bid until it is hit by a seller. Alternatively, if the buyer likes an offer already posted on the exchange, the buyer can lift that offer to complete the trade.

For open outcry trading, the buyers work through their FCM to trade on the exchange. Buyers can submit two types of orders with their FCM, a limit order (a bid at a specific price) or a market order (which will buy the current offer in the trading pit). FCMs will work a limit order until it is executed in the pit or until the floor trader indicates that the order is unlikely to trade. At this point, the buyer can cancel the order or raise its bid. In this manner, the buyer can adjust its bid until the trade is executed.

Since the transparent exchanges trade standard products and trading is anonymous, selection is made on product availability, credit availability, and price.

b. Inter-dealer (Voice) Brokers

Inter-dealer or voice brokers facilitate trades in the wholesale market for electricity and gas. Brokers communicate bids and offers to market participants through squawk boxes[5] and telephone calls. Brokers work with buyers and sellers to

[5] A squawk box is an intercom speaker used for communication between brokers and traders. The box allows brokers to broadcast market information to traders and to have one-on-one conversations with traders. PG&E records all communication on its squawk boxes as part of its trading process controls.

facilitate trades. Once completed, brokers confirm the transactions with both parties and may initiate financial clearing with both NYMEX and the ICE. Brokers facilitate the trading of physical and financial gas and electric products. Brokers, as part of their price discovery role, provide price reporting services to subscribing clients.

Buyers communicate bids to the broker. If a seller hits the bid the trade is completed. If a seller does not hit the bid, the buyer can ask the broker to work its bid in the market. The broker will provide the buyer feedback if its offer is not hit by a seller. The buyer can adjust its bid until it is hit by a seller. Alternatively, if the buyer likes an offer communicated by the broker, the buyer can lift that offer to complete the trade. Since brokers facilitate trades of standard products and trading is anonymous, selection is made by product availability, credit availability and price.

c. Spot Markets

The spot market for electricity and gas is the wholesale market for day-ahead electric energy and natural gas. Day ahead for electricity normally includes two, two-day strips for weekends (Friday-Saturday and Sunday-Monday) and other combinations of days to accommodate holidays. Day ahead for gas normally includes a 3-day strip for weekends (Saturday-Monday) or a longer combination of days to accommodate holidays.

The bilateral spot market consists of buyers and sellers communicating bids and offers to counterparties through telephone calls and Instant Messaging ("IM"). Traders negotiate until a trade is completed. Spot trades are normally executed and then confirmed over the phone by schedulers and not with paper confirmation documents. Spot market trades are also executed though voice brokers, ICE and NGX.

Buyers communicate bids to potential sellers. If a seller hits the bid the trade is completed. If a seller does not hit the bid, the buyer adjusts the bid to entice the seller or they can call another potential seller. The process continues until the buyer finds a willing seller at the buyer's price. Alternatively, sellers communicate offers to potential buyers, negotiate prices, and keep searching until they find a willing buyer. It is common for buyers and sellers to trade through brokers, exchanges and the bilateral spot market simultaneously. Selection is made by product availability, credit terms, credit availability, and price.

d. On-Line Auctions

On-line auctions facilitate the competitive purchase or sale of electricity and gas with approved counterparties. In an on-line energy auction, PG&E posts a commodity for purchase or sale on a secure internet site, while qualified bidders compete in a live format to provide PG&E with the most advantageous price. PG&E posts energy products for purchase or sale on the secure auction web site. Approved bidders are invited to participate and compete against one another in a live auction. Bidders are required to meet PG&E's credit qualifications in order to participate. Selection is made by product availability and price.

e. RPS Solicitations

RPS bidders include large corporations, small businesses, and individuals with ideas. Offers come from existing and proposed projects in California, the Pacific Northwest, and the Desert Southwest in response to PG&E's annual solicitation. Within California, the offers consist of those both on and off the CAISO grid. Following a Commission decision authorizing an RPS solicitation, PG&E issues a Request for Offer ("RFO") and then reviews the offers it receives. PG&E short-lists offers and then negotiates with the bidders to execute an RPS agreement. The RPS solicitation process is described in more detail below in Volume 1, Section III.A.5, below.

f. Energy Product Solicitations and RFOs

PG&E can also obtain electric and gas products through all-source solicitations. PG&E defines the products it is seeking in its RFO and then reviews bids and offers received. PG&E can conduct RFOs for long-term resources, such as the 2004 Long Term Request for Offer ("LTRFO"), or for shorter-term products, such as capacity to satisfy Local or System RA requirements.

g. Bilaterally Negotiated Contracts

Bilateral negotiations are used for the purchase and sale of electric and gas products. The phrase "bilateral negotiations" is generally used in the context where negotiations take place in a one-on-one setting rather than as a part of a competitive solicitation. The process consists of direct one-on-one negotiations, but negotiated terms and conditions are constantly being weighed against best available market price benchmarks to justify the transactions, similar to selecting the best transactions in RFOs.

The decision to proceed is based least-cost, best-fit principles. The evaluation criteria and methodologies are very similar, if not the same, as those used to evaluate transactions in recent and comparable product RFOs. PG&E uses the best available market price benchmarks in the evaluation process.

h. Inter-Utility Swaps

Inter-utility swaps can be used for the purchase and sale of electric and gas products. Negotiations take place in a one-on-one setting. Inter-utility swaps historically have been used for transactions that offer some form of operational benefits to both parties. However, as transactions have become more purely market oriented, such swaps are more simply combined buy and sell transactions, and evaluated as such. There is a diminishing need to make this product distinction. Inter-utility swaps have become less unique as parties can buy or sell each leg of the transaction from multiple parties. The process consists of direct one-on-one negotiations, but negotiated terms and conditions are constantly being weighed against best available market price benchmarks to justify the transactions. PG&E has not recently executed swaps with other utilities because of the combination of a current lack of need, and more readily available market opportunities for similar products from numerous other market participants.

The decision to proceed is based on least-cost, best-fit principles. Evaluation criteria and methodologies are very similar, if not the same used to evaluate transactions in recent and comparable product RFOs. PG&E uses the best available market price benchmarks in the evaluation process.

5. PG&E's Procurement Contracting Methods and Practices

In this section, PG&E describes its electric procurement methods and practices for short-term, medium-term and long-term contracts. Table Vol. 1, IIIA-5 below reflects the procurement methods and practices that PG&E is authorized to use and PG&E's request that PRG review be required for transactions with delivery dates later than six calendar months from execution, or that have contract durations greater than six calendar months. Currently, the PRG trigger is three months. The six month request is discussed in Volume 2, Section II.A.1

TABLE VOL. 1, IIIA – 5
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT METHODS AND PRACTICES

Item #	Transaction Process	Description	Prior Authorization
1	Competitive Solicitations (RFO)	Widely distributed request for offers or proposals. Required items include among other things: Description of product requirements, term, minimum and maximum bid quantities, scheduling and delivery attributes, credit requirements, and pricing attributes.	D.02-10-062 D.04-12-048 AL 2615-E
2	Direct bilateral contracting with counterparties for short-term products (*e.g.*, six months or less)	Bilateral process for products procured with a term six months or less. Investor-owned utilities (“IOU”) demonstrate that such transactions are reasonable based on available and relevant market data supporting the transaction. The demonstration may include showing competing price offers, result of market surveys, broker and online quotes, and/or other source of price information such as published indices, historical price information for similar time blocks, and comparison to RFOs completed within one month of the transaction.	D.02-10-062 D.04-12-048 AL 2615-E PG&E is proposing to revise the PRG process from a 3-month to a 6-month contract term or commencement date before PRG review is required. *See* Volume 2, Section II.A.1.
3	Inter-Utility Exchanges	Exchange with other regulated utilities and other load-serving entities negotiated through private negotiation crafted to best fit the resources and needs of both parties.	D.02-10-062 D.04-12-048 AL 2615-E
4	ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead	Spot market transactions are authorized to balance system and short-term needs. IOUs justify their planned spot market purchases if they exceed 5% of monthly needs.	D.02-10-062 D.04-12-048 AL 2615-E
5	Transparent exchanges, such as Bloomberg and Intercontinental Exchange, voice and on-line brokers	Electronic trading exchanges for transparent prices.	D.02-10-062 D.03-12-062 D.04-12-048 AL 2615-E
6	Utility ownership of generation (interim rules set in D.04-01-050)	IOU proposes to buy or construct generation.	D.02-10-062 D.04-01-050 D.04-12-048 AL 2615-E
7	Open Access Same-Time Information Systems (“OASIS”)	Procure standard electric transmission products from transmission providers throughout the WECC region at FERC tariffed rates and voice and on-line brokers.	D.03-12-062 D.04-12-048 AL 2615-E
8	Negotiated bilateral contracts for non-standard products which terms exceed six months provided that the IOUs include a product justification in quarterly compliance filings.	Process to purchase products provided they are included in quarterly compliance filings to justify the need and process in each case. Terms and conditions are benchmarked against the best available market information for similar products recently offered.	D.03-12-062 D.04-12-048 AL 2615-E

TABLE VOL. 1, IIIA – 5
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT METHODS AND PRACTICES
(CONTINUED)

Item #	Transaction Process	Description	Prior Authorization
9	Transparent exchanges to include voice and on-line brokers	Transparent price products from voice and on-line brokers.	D.03-12-062 D.04-12-048 AL 2615-E
10	Electronic Auction	IOUs are authorized to conduct procurement using an electronic auction format.	D.04-12-048 AL 2615-E
11	Generator Requests for Proposals	IOUs can bid in open season or RFPs held by generator owners.	D.04-01-050 AL 2615-E

In the remainder of this section, PG&E describes its procurement practices and methods for: (a) short- and medium-term procurement transactions; (b) long-term transactions; (c) RPS transactions; and (d) the length of time between the date contracts are executed and when actual deliveries commence.

a. Procurement Practices and Methods for Short-Term and Medium-Term Transactions

This section describes PG&E's methods and practices for short-term and medium-term procurement transactions. PG&E utilizes various Commission-approved transaction methods that are set forth in Table Vol. 1, IIIA-5 for short- and medium-term transactions.[6]

PG&E's electric procurement process is not a one-time event. Rather, it is comprised of a series of ongoing analyses and activities that focus on different time frames and decisions. This process ensures that resources are available to meet energy and ancillary service requirements and allows PG&E to minimize the cost of generation and risks by participating in a variety of transactions over time.

The short- and medium-term electric procurement time frames include: (1) multi-year;[7] (2) annual; quarterly, and monthly; (3) intra-month and weekly; (4) daily; and (5) hour-ahead. The CAISO also manages a "real-time" market. The procurement process is conceptually identical in all time frames insofar as all considered resources are reviewed on an equal basis in determining how to meet

[6] Short-term and medium-term contracts that are part of PG&E's electric portfolio are also discussed in Volume 1, Section IV.C.2 – Supply-Side Resources.

[7] For this discussion, the term "multi-year" is limited to less than five years.

PG&E's demand and energy requirements in a least cost manner. The input assumptions and the granularity of those assumptions differ. PG&E begins by determining total load requirements, including customer retail demand, wholesale sales, transmission and distribution losses, ancillary services, and any and all operating constraints. PG&E then determines the quantity of generation from baseload "must-run" resources such as the Diablo Canyon Power Plant ("DCPP"), QFs, and DWR allocated contracts. Finally, PG&E assesses market conditions in order to optimize production from dispatchable resources and market transactions. PG&E's objectives are to meet any remaining load requirements as well as extract value from resources when it is economic to sell into the market.

The remainder of this discussion summarizes the short- and medium-term procurement process and describes some of the Commission-approved transaction methods that PG&E has undertaken in each time frame since it has resumed electric procurement.

(1) Multi-year

PG&E initially determines its need for short- and medium-term transactions. Multi-year transactions typically involve competitive solicitations that are reviewed in consultation with the Procurement Review Group ("PRG"). After negotiating a multi-year transaction, PG&E submits the agreement to the Commission for approval via an advice letter, if the term of the transaction is less than five years. Use of an Independent Evaluator ("IE") is not required.

(2) Annual, Quarterly, and Monthly

PG&E performs and updates assessments of its net open position for a 12-month forward period on a regular basis to determine whether additional resources are required or it has excess resources for potential surplus sales. This process ensures that PG&E has resources to meet requirements, and determines by the close of the month prior to an operating month that it will control resources within 5% of expected requirements, as recommended by the Commission in D.02-10-062.

The analysis is the same as that employed for the multi-year time frame, with the primary difference being the assumptions used—forecasted loads, resource availability, gas prices, hydro availability and market prices are further refined as PG&E moves closer to the operating period, hence resource requirements and market opportunities become clearer.

Forward Energy Products (*e.g.*, term, balance-of-month and balance-of-week purchases and sales) are transacted to diversify the portfolio and reduce reliance on spot markets. Currently, transactions with a delivery date later than three calendar months from execution, or for a term greater than three calendar months are reviewed by the PRG.[8] PG&E's monthly forward transactions represent the majority of PG&E's market transaction volume, and are primarily one-month purchases or sales of fixed price, standard block on-peak and off-peak energy, although some transactions span two or three months. Bilateral contracts are often used. Typically, bilateral contracts are benchmarked against pricing information obtained from recent competitive solicitations for a similar product or against forward price curves. In addition, brokers play a critical role in almost all of these transactions. Voice brokers and electronic exchanges are used for the purpose of price discovery and matching buyers with sellers in an anonymous fashion.

(3) Intra-month and Weekly

As part of an integrated process, results from the actions described in the previous section determine the amount of the residual open position (long or short) that is carried into the prompt month. Inside the month time horizon, PG&E reviews the availability of resources, hydro conditions, and makes an assessment of market prices and conditions to further assess how best to manage the open position. If market transactions are needed, the transaction methods listed in the foregoing section are generally used.

(4) Daily

In day-ahead procurement PG&E strives to balance projected energy requirements with resources, and provide hour-ahead traders and real-time operators with appropriate resources to respond to changes that may occur in system requirements subsequent to day-ahead trading. On a daily basis PG&E conducts a least-cost analysis to determine unit dispatch and market transactions to meet energy and ancillary services requirements.

Day-ahead trading generally occurs between 6 and 7 a.m. in the day prior to the operating day. The day-ahead market continues to evolve in terms of participants,

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[8] PG&E is requesting that PRG review be required for transactions with a delivery date later than six calendar months from execution, or for a term greater than six calendar months. *See* Volume 2, Section II.A.1.

products and character. Currently the market usually trades "standard" on-peak and off-peak "packages" of multiples of 25-MW blocks with specified delivery points. While some basis spread products are traded, there is only sporadic trading of hourly energy products or other non-standard products such as options. PG&E actively participates in the daily energy market using a combination of transparent exchanges with voice and on-line brokers, and direct bilateral transactions with counterparties.

PG&E has adapted its daily procurement process to incorporate the opportunities available in the day-ahead market as well as its must-run and must-take resource requirements. Similar to the market products discussed above, many of the must-take contracts are for standard blocks of on-peak hours. These contracts do not match PG&E's load profile and often results in excess energy during some hours while leaving PG&E short during other hours. To manage this PG&E may: (1) either re-dispatch resources to the extent it is feasible or dispatch other flexible resources; (2) engage in non-standard product transactions; and (3) make a concerted determination to sell or purchase quantities of energy in the hour-ahead market in order to maximize the value of its energy and minimize real-time imbalances.

(5) Hour Ahead

"Hour-ahead" planning is something of a misnomer since it effectively begins at the conclusion of day-ahead trading. As day-ahead analysis and trading occurs early in the morning prior to the operating day, there can be substantial subsequent changes to operating requirements. PG&E prepares weather-adjusted load forecasts throughout the day to determine if changes in generation or system operation are required. Further, unit outages and transmission outages and constraints may also affect resource requirements prior to real-time. In order to balance its portfolio during this time frame, PG&E's hour-ahead staff has several resources at its disposal. Dispatchable resources are updated with incremental unit dispatch prices. Hour-ahead personnel will then optimize the portfolio, based on operating requirements and market opportunity costs, whether and which generating resources should be adjusted to minimize system costs, and whether market transactions are required or beneficial.

The hourly market, while active, is far less transparent than the day-ahead market or the real-time market. As there are few brokers operating in this market and nascent electronic exchange opportunities, the bulk of transactions are bilateral in nature, making it difficult to generally characterize the hour-ahead market. Despite this, PG&E participates in the hour-ahead market to optimize its resources and market transactions to reduce costs.

(6) CAISO "Real-Time"

While PG&E strives to achieve balanced loads and schedules in the Day- and Hour Ahead time frames, mismatches are inevitable. Causes could be changes in electric demand, resource availability, or transmission availability. The CAISO "Real-Time" market is where load/resource balance is the goal. Imbalances after the close of the Hour-Ahead market are settled at the CAISO's "ex-post" price (*e.g.*, PG&E sells/purchases energy to/from the CAISO).

b. Procurement Methods and Practices for Long-Term Transactions

In this section, PG&E discusses procurement contracting methods and practices for various long-term (*e.g.*, 5 years or longer) procurement transactions.

(1) Negotiated Bilateral Contracts

PG&E generally does not negotiate bilateral contracts for long-term procurement. However, PG&E has conducted bilateral negotiations when appropriate and beneficial to its customers. For example, PG&E's acquisition through a bilateral transaction of the Gateway facility[9] stemmed from a settlement of PG&E's claims against Mirant. In its application to the Commission requesting approval of the acquisition and completion of Gateway, PG&E benchmarked the economics of the acquisition by comparing the cost to complete Contra Costa 8 ("CC8") to the cost of other, similar power plant acquisitions recently approved by the Commission, namely the Mountainview and Palomar facilities. Both Mountainview and Palomar were viewed as "fleeting opportunities" for below-market acquisitions. PG&E was able to demonstrate that Gateway's forecast completion cost was lower than those other two fleeting opportunities on a $/kilowatt ("kW") basis. The Commission approved PG&E's acquisition of Gateway in D.06-06-035.

If PG&E considers long-term bilateral agreements in the future, the winning 2004 LTRFO bids may provide an appropriate starting point for market benchmarks to review those bilateral agreements. These winning bids are the result of a

[9] The Gateway Facility was previously referred to as Contra Costa 8.

competitive solicitation and are good measures of market prices for dispatchable and operationally flexible products available at the time the winning bids were selected.

(2) Competitive Solicitations – PG&E's Experience With the 2004 LTRFO

PG&E recently concluded its 2004 LTRFO, which resulted in seven contracts that were recently approved by the Commission. The 2004 LTRFO process was complex and intensive. Below, PG&E provides a brief description of the various elements and aspects of the 2004 LTRFO process as an example of how long-term procurement solicitations can be administered.

PG&E’s 2004 LTRFO involved both internal and external resources. PG&E formed an internal steering committee for the 2004 LTRFO to ensure the goals of the LTRFO and D.04-12-048 were met. The committee was responsible for establishing policies, making key decisions about offers and recommending the shortlist of projects and ultimately the final contracts for execution. PG&E also received feedback from market participants on its proposed LTRFO solicitation process before starting the process. After a pre-offer conference, in response to this feedback, PG&E modified the 2004 LTRFO protocol, including modifications to extend the schedule and increase the number of offer variations allowed for each offer. PG&E also made modifications to the Purchase and Sale Agreement (“PSA”) and Power Purchase Agreement (“PPA”) contracts based on feedback from the market participants prior to submission of final offers.

The actual 2004 LTRFO solicitation process included a number of key milestones. First, PG&E distributed a draft RFO and online registration for purposes of a pre-offer conference. PG&E established a location on its public website with information relevant to the 2004 LTRFO.

Second, PG&E held a Pre-Offer Conference to discuss the draft of PG&E’s 2004 LTRFO for PPAs and Facility Ownership.

Third, PG&E issued its original 2004 LTRFO for PPAs and Facility Ownership and later revised the LTRFO in compliance with D.04-12-048.[10] Participants were then required to initiate Electric and Gas Interconnection Studies

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[10] This revision implemented a methodology to evaluate PPA offers and PSA offers directly on a head-to-head basis. In addition, an IE was selected, in consultation with the PRG, and retained. PG&E also included the solicitation for offers for the Humboldt Bay Power Plant (“HBPP”) in the revised LTRFO.

including a System Impact Study ("SIS") and Facility Study ("FS") with the CAISO and to submit to PG&E Gas Transmission and Distribution department or other applicable gas transmission company a request for a Preliminary Application for Gas Service.

Fourth, participants were requested to submit a Notice of Intent ("NOI") to offer and then submitted their initial offers. The IE was present to witness the opening of initial offers.

Fifth, PG&E notified participants of shortlisted projects and issued drafts of PPAs and PSAs and requested additional data from participants with projects on the shortlist.[11]

Sixth, PG&E issued revised drafts of PPAs and PSAs to participants. Participants with projects on the shortlist submitted final offers. The IE was present to witness the opening of final offers.

Finally, PG&E was involved in extensive negotiations with winning bidders and then executed agreements and presented them for approval by the Commission.

PG&E's 2004 LTRFO included certain eligibility requirements that were designed to ensure a diverse selection of resources, capacity, contract terms and technologies. These requirements were also designed to ensure that the resources would be timely constructed and online in time to meet resource needs in the 2008 through 2010 time frame.

- **PPAs:** For PPAs, new generating facilities were required to have a Commercial Operations Date ("COD") no earlier than January 1, 2007, and no later than May 31, 2010. Offers required a minimum term of five years and a minimum size of 25 MW or greater. Offers were required to provide for firm physical delivery of generation to a busbar in the North of Path-15 ("NP15") area. Only "unit specific" offers were accepted. Offers were required to confer upon PG&E exclusive rights to the unit's capacity, subject to CAISO requirements.

- **Facility Ownership:** For Facility Ownership, all generating facilities were required to have a Guaranteed Commercial Availability Date no earlier than

[11] Participants providing offers for HBPP were requested to provide offers for a PSA, an Engineering, Procurement and Construction ("EPC") and the sale of development assets.

January 1, 2007, and no later than May 31, 2010. Facilities were required to have a design life of 30 years, a size no less than 25 MW at any one site, and construction with new equipment. A proposed project's generation was required to physically interconnect to a busbar within the NP15 area.

- **Humboldt Generation:** For the Humboldt Bay area, PG&E required generation facilities to have a Guaranteed Commercial Availability Date no earlier than January 1, 2007, and no later than August 31, 2009. Facilities were also required to have a design life of 30 years, total peak capacity of at least 135 MW on a single site, functional specifications necessary for Humboldt area reliability, and be constructed with new equipment. A proposed project's generation was required to be physically interconnected to a busbar within Humboldt County.

- **Qualifying Facilities:** An existing QF in PG&E's service territory as of November 2, 2004, was required to meet the requirements of FERC's QF rules and not have waived these rights to PG&E. QFs also had the option to provide delivery within the ZP26 area. Offers were required to be for a minimum term of five years and a minimum of 1 MW or greater.

- **New Resources:** The 2004 LTRFO was only open to new resources (with the exception of existing QFs) because the purpose of the solicitation was to implement the directives of D.04-12-048 to bring new sources of reliable supply to northern California. For the purpose of the 2004 LTRFO, PG&E considered "new" resources to be resources that had not begun construction. PG&E assumed that resources that had begun, but not yet completed, construction would likely be completed without the need for contracts via PG&E's 2004 LTRFO.

- **Other Eligibility Requirements:** Additional 2004 LTRFO requirements included: (1) a Transmission System Impact Study and a Preliminary Application for Gas Service; (2) deposit requirements; and (3) site control.

PG&E also included a Greenhouse Gas ("GHG") adder in the evaluation of the 2004 LTRFO bids. In D.04-12-048, the Commission specified that a Greenhouse Gas GHG adder, in dollars per ton of carbon dioxide ("CO_2"), be used to calculate the cost of CO_2 emissions. In D.05-04-024, the Commission adopted a particular set of values for the GHG adder: for delivery year 2004, $8.00 per ton of CO_2, with escalation at 5% per year for delivery in subsequent years. For delivery year 2010, this amounts to $10.72 per ton of CO_2. PG&E used this GHG adder curve in project evaluations. For each offer, PG&E's modeling yielded estimates of the anticipated CO_2 emissions, based on the capacity factors associated with that offer's generating unit. The estimated quantities of CO_2 emitted were then multiplied by the costs per ton specified in the GHG adder. This calculation yielded the variable cost associated with CO_2 emissions. GHG adder cost was measured in present value (2006) dollars per kW-year of generating unit capacity.

In accordance with D.04-12-048, PG&E also contracted directly with an IE, in consultation with PG&E's PRG. The scope for the IE's responsibilities included the following activities: (1) review and comment on the appropriateness of PG&E's evaluation methodology, with a focus on how PPA and utility ownership offers are compared directly; (2) review and assess whether PG&E actually implemented the evaluation methodology as represented; (3) use the IE's Response Surface Model to check the numerical results for PG&E's market valuation of the contracts; and (4) deliver to the PRG, under existing confidentiality protections, the Response Surface Model and the results produced by the IE in performing the check of numerical results, as described above.

PG&E met with the PRG at least 15 times to discuss aspects of the 2004 LTRFO evaluation. The PRG was also consulted in the selection of the IE. PG&E held two workshops with the PRG to discuss PG&E's evaluation methodology in depth. PG&E's evaluation framework for credit was also discussed extensively with the PRG. In addition, PG&E met with the PRG to discuss evaluation of initial offers, final offers, and during final negotiations.

PG&E is satisfied with the results of the process developed for its 2004 LTRFO and intends to follow largely the same process in its next LTRFO. PG&E intends to retain an IE in case it chooses to submit its own bid, and involve the PRG in various stages of the future LTRFO process.

c. Procurement Methods and Practices For RPS Transactions

The California RPS Program was established by California State Senate Bill ("SB") 1078, effective January 1, 2003.[12] The RPS Program requires that a retail seller of electricity such as PG&E purchase a certain percentage of electricity generated from eligible renewable energy resources. Each utility regulated by the Commission is required to increase its total procurement of capacity and energy generated by eligible renewables by at least 1% of annual retail sales per year so that 20% of its retail sales are supplied by eligible renewables by 2010.

PG&E procures RPS resources through competitive solicitations and bilateral negotiations. In bilateral negotiations, PG&E may execute contracts with renewable suppliers for one month up to 20 years, or more. These contracts are filed for Commission approval by advice letter. For competitive solicitations, PG&E conducts annual RPS solicitations. Prior to issuing its solicitations, the RPS procurement plan and solicitation protocols are submitted to the Commission for approval.

The following key milestones have already been achieved in PG&E's 2006 RPS solicitation: (1) PG&E issued the Solicitation Protocol; (2) participants submitted NOI to Bid containing basic project information and a reservation to attend the pre-bid conference[13]; (3) PG&E held a Pre-Bid Conference; (4) participant's offer(s) were submitted by the Offer Submittal Deadline; (5) PG&E selected a Shortlist of Offers for further negotiations; (6) participants selected for the Shortlist are required to post a Bid Deposit and execute a Confidentiality Agreement; and (7) the Commission released the Market Price Referent ("MPR") used to calculate how much of bidder's price will be paid directly by PG&E under the PPA and how much, if any, will be eligible to be paid as Supplemental Energy Payments ("SEP") by the Public Good Charge account administered by the California Energy Commission ("CEC").

The remaining milestones in the 2006 RPS Solicitation are: (1) PG&E will conduct negotiations and reach final agreements with short-listed bidders; (2) the final

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[12] *See* Cal. Pub. Util. Code §§ 399.11-399.25 and Cal. Pub. Res. Code §§ 25740-25751.

[13] The NOI to Bid is nonbinding and failure to submit it by the schedule date will not disqualify a participant.

agreements will then be shared with the PRG[14]; (3) PG&E and final bidders will execute agreements; and (4) PG&E will submit agreements for Commission approval via an advice letter filing. If a bid price exceeds the MPR and the bidder intends to seek SEPs from the CEC, bidders also submit an application to the CEC for SEP funding.

PG&E's 2006 RPS Solicitation includes the following eligibility requirements:

- Projects must be certified as eligible renewable resources by the CEC.
- Projects must use one or more of the following renewable resources or fuels:
  - Biomass
  - Biodiesel
  - Fuel cells using renewable fuels
  - Digester gas
  - Geothermal
  - Landfill gas
  - Municipal solid waste
  - Ocean wave, ocean thermal, and tidal current
  - Photovoltaic
  - Small hydroelectric (30 MW or less)
  - Solar thermal
  - Wind
- Existing eligible renewable projects are eligible to bid.
- The project must either: (i) be located in California; or (ii) if located outside of California, demonstrate delivery of its energy to an in-state market hub or in-state substation. The bidder and PG&E may negotiate a delivery point location that is located out-of-state as long as the energy is ultimately

[14] PG&E consults with the PRG throughout the RPS solicitation process, including consultation with respect to solicitation design and shortlisting.

delivered into the CAISO-controlled Grid or a location that otherwise satisfies applicable CPUC delivery rules to qualify as an RPS eligible resource.

- Each bidder is solely responsible for securing all necessary interconnection, distribution, transmission, and scheduling services associated with the bidder's project.

As with the 2004 LTRFO, in consultation with the PRG, PG&E contracts directly with an IE for RPS Solicitations.

d. Procurement Methods and Practices: Length of Time Between Contract Date and Delivery Commencement

The time between contract execution and when delivery of a product begins depends on resource type (*e.g.*, existing or newly built resources), as well as the short- or long-term nature of the contract. For short-term contracts deliveries can begin as late as one year after execution, such as an RA contract signed in 2005 for Summer 2006. These contracts become effective when executed.

Medium-term contracts that are consistent with existing procurement authority may be filed for approval via advice letter filings, which could take up to a year. Long-term contracts (except for renewable contracts resulting from an RPS solicitation) are filed for approval via an application. The application, approval and permitting process for such contracts typically takes over a year. For contracts that require construction of facilities, construction will not begin until all regulatory approvals and permits are acquired and actual deliveries may not begin until five or more years after contract execution. Thus, for long-term contracts with newly-built resources, it could take several years or more between contract execution and the beginning of deliveries to allow for permitting and construction.

For renewable generation, it typically takes one year from a RFO issuance until Commission approval, and two to three years from Commission approval until deliveries are targeted to commence, for a total of three to four years from the RPS RFO issuance to actual contract deliveries.

6. Proposed Transaction Timing for Upcoming RFOs

Upon Commission approval of PG&E's 2006 LTPP, PG&E will implement its authorized plan through various processes, including solicitations, bilateral negotiations and participation in various markets. The following section describes PG&E's proposed RFOs for the next one to five years.

a. Renewable RFOs

As described in Volume 1, Section V.D, PG&E will continue to issue annual Renewable RFOs to aggressively pursue RPS targets. These RFOs offer renewable developers a number of procurement alternatives—such as PPAs with and without buyout options, turnkey utility ownership, and greenfield development—in order to identify those mechanisms which are in the best interest of its customers. The developers include large corporations, small businesses, and individuals with ideas. Contracts with these developers typically range from 10 to 20 years; however, PG&E will also consider other contract lengths. The types of contracts include Power Purchase and Sale Agreements for As-Available Products and Power Purchase and Sale Agreements for Firm Products (which include peaking, baseload, and dispatchable products). Once PG&E issues these RFOs, the offers received are reviewed. PG&E shortlists offers and then negotiates with bidders to execute contracts. Executed contracts will be submitted to the Commission for approval.

PG&E's 2006 RPS RFO is currently in progress. PG&E issued the solicitation on June 30, 2006, and held a bidders conference on July 20, 2006. Following receipt of offers on September 8, 2006, PG&E performed a rigorous review of the offers, including follow-up requests to sellers for supplemental information. PG&E notified shortlisted bidders on November 2, 2006. Negotiations will follow for two to six months, depending on how close the parties are in the PPA terms and price. Executed contracts will be followed by an advice letter filing to the Commission, with an expected Commission approval within 180 days.

PG&E will continue to refine its renewable RFOs based on developer feedback, over the future planning horizon. PG&E also anticipates developing new programs such as the emerging renewable resource program described in Volume 2, Section I.B.5, in order to assess and prepare for higher renewables goals in the post-2010 time frame. As PG&E's procurement practices evolve, PG&E may identify the need for other types of renewables RFOs. These yet-to-be determined renewables RFOs will be issued only upon Commission approval.

b. Short-Term/Medium-Term RFOs

The residual net long/short energy and RA capacity requirements are the positions that PG&E may need to manage on a short-term (up to and including 1 year) and medium-term (greater than 1 year and less than 5 years) time horizon within the operating targets discussed in Volume 1, Section III.B.1.a. Specifically, if the monthly subperiod positions fall outside the operating targets, strategies are developed and executed to bring the portfolio back to within the targets. PG&E's energy and capacity needs are managed using Commission-approved transaction contracting methods in Advice Letter 2615-E, including competitive solicitations. PG&E will continue to issue medium-term RFOs to manage the residual net long/short energy and RA capacity requirements. These RFOs can be issued for a variety of electric products. These electric products are described in Volume 1, Section III.A.3.a. The contracts resulting from these RFOs can range from greater than one year to less than five years in length. Once PG&E issues these RFOs, the offers received are reviewed. PG&E shortlists offers and then negotiates with the bidders to execute agreements. Project costs are reviewed with the PRG during the process. Executed contracts are filed with the Commission through either the Quarterly Procurement filings or through stand-alone advice letter filings.

Resource adequacy requirements will be met by PG&E using competitive solicitations or other previously approved Commission mechanisms. As required by the Commission, PG&E will file its plan to meet 90% of its System RA requirements for the summer months of 2008 (*i.e.*, May-September) by September 30, 2007. Subsequently, all months require a 100% commitment to be in place one month ahead. PG&E will review its RA procurement activities with the PRG and file Advice Letter for necessary Commission approvals.

PG&E is required to acquire 100% of its share of the local area resource ("LAR") requirement in CAISO defined, transmission-constrained areas. Since the rules for 2008 LAR procurement will not be known until mid-2007, PG&E must estimate its share of LAR utilizing information from 2007 in order to be prepared to complete procurement by late October 2007. PG&E will seek to procure its LAR with Commission approved mechanisms at the lowest cost while considering the CAISO's area and sub-area RA needs.

c. LTRFOs

PG&E's recommended plan implements the State Loading Order and aggressively pursues renewable resources, as well as energy efficiency and demand response. However, even with these efforts, there will be a need for additional new generation in Northern California. As discussed in Volume 1, Section V.F.6, PG&E

will issue a new all-source LTRFO in 2007 to procure 2,300 MW in new dispatchable and operationally flexible generation resources it has identified in this long-term plan. This solicitation will seek facilities to meet the identified need for the 2011-2014 time frame. The eligibility requirements, rules, and process are anticipated to closely match those of the 2004 LTRFO described in Volume 1, Section III.A.5.b(2). Specifically, the eligibility requirements will be designed to ensure a diverse selection of resources, capacity, contract terms and technologies. The LTRFO will consider PPAs as well as utility ownership projects. The lengths of these contracts may be 10 years or more. PG&E anticipates filing for Commission approval upon execution of contracts with the winning bidders.

7. The Application of Least-Cost, Best-Fit and the Loading Order in PG&E's Procurement Planning and Transactions

Least-cost, best-fit provides for resource alternatives to be selected based on their relative cost-effectiveness and their ability to meet the specific needs of the portfolio. A resource's cost-effectiveness is determined relative to common market benchmarks or "market value," as explained below. A resource's portfolio fit can be a qualitative assessment or quantitative measure that represents how well its energy profile, location, and other operating characteristics meet the needs of the portfolio for a particular product in a given location.

In planning and procurement decisions, PG&E applies a consistent evaluation methodology to both supply-side and demand-side resources. By applying least-cost, best-fit principles to supply-side and demand-side alternatives, PG&E obtains the lowest cost for customers for a given set of portfolio needs. PG&E's procurement evaluation methodology considers both the market value and the portfolio fit of alternative resources that are available.

a. Market Valuation

Market value represents a resource's net market value from a market perspective, based on its costs and benefits, regardless of its fit with the rest of PG&E's portfolio. The costs that PG&E uses in calculating a resource's net market value include the value that the Commission has placed on CO_2 emissions.

In valuing demand-side alternatives, PG&E uses the Commission's Standard Practice Manual's[15] total resource cost ("TRC") test. Under that TRC test, the costs that PG&E and its customers are expected to incur in implementing an alternative resource[16] are compared to the expected benefits that would be obtained from that alternative resource. Those benefits include the energy and/or capacity costs that would be avoided by utilizing that alternative resource. As long as PG&E's avoided energy and capacity costs are based on market prices, then PG&E's evaluations of supply-side resources and demand-side resources are consistent, and make it possible to compare supply-side resources to demand-side resources.

b. Portfolio Fit

Portfolio fit assesses how well a resource alternative matches PG&E's portfolio needs. For example, a resource that produces energy during time periods in which PG&E's portfolio is expected to be long (*i.e.*, periods in which PG&E expects to make spot market energy sales) has a poorer portfolio fit than a resource that produces energy during time periods in which PG&E's portfolio is expected to be short (*i.e.*, periods in which PG&E expects to make spot market energy purchases). As a result, the portfolio fit of a resource is different from, but complementary to, the net market value of that resource.

In the planning phase, when preparing a long-term procurement plan, PG&E considers portfolio fit based on how well a particular resource provides the power products that need to added to the portfolio. Not all resources provide the same products. For example, photovoltaic distributed generation and energy efficiency do not provide dispatchable peaking energy.

In the planning phase, PG&E first identifies the types and amounts of power products that it needs to fill its open position over the planning horizon. Those power products include energy products (baseload, peaking and shaping), capacity or RA products, and ancillary services products (*e.g.*, spinning, non-spinning, regulation, and black-start capacity). Then, PG&E identifies the energy products that each alternative

[15] *Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, issued by the Commission in October 2001.

[16] When evaluating demand-side alternatives, PG&E considers the costs customers incur due to participation in demand-side program as well as the costs that non-participating customers incur due to that program.

resource can provide (*e.g.*, baseload energy and dispatchable shaping or peaking energy.)

Most resources can provide a capacity product, or have an RA value that PG&E can estimate by using the Commission-adopted RA counting rules. However, some resources are more likely to provide energy in the hours when the system's peak demand is most likely to occur, and which as a result have a higher RA value (per unit of installed capacity). With respect to ancillary services, a combustion turbine ("CT") can provide quick start capacity and can be used in emergencies to replace resources that are unavailable because of forced outages. Certain demand response ("DR") programs can also provide emergency capacity, because the demand reductions under that program can be activated on short notice (e.g., within 10 minutes to qualify as non-spinning reserves).[17] CTs and DR however, are not suited to provide system regulation services because they cannot respond instantaneously to automatic generation control ("AGC"). Regulation services are generally provided by units that are on-line, and operated under automatic control to continuously balance generation and load.

In the procurement phase, when evaluating transactions, portfolio fit can be a qualitative assessment or quantitative measure that represents how well a resource fits the portfolio's need. In addition to the market valuation, resources are compared based on their ability to meet the particular need being met, or their ability to provide additional features that are complementary to the portfolio. For example, if the proposed resource is not dispatchable by the utility, the offer with a generation profile that best matches the hourly profile of the open position will score more highly on PG&E's portfolio fit measure. Other portfolio fit considerations can include location and the volatility of the remaining portfolio open position.

c. Loading Order

According to EAP II, cost-effective EE and DR are preferred to meet the State's growing energy needs, followed by cost-effective renewable and distributed generation, and finally clean and efficient fossil-fired generation. The EAP II also

[17] *Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria (MORC),* revised April 6, 2005, p. 3.

requires improvements to T&D system to support demand growth and enable the interconnection of new generation.[18]

PG&E's 2006 LTPP follows the State Loading Order. PG&E's recommended plan adds cost-effective energy efficiency and demand response in order to meet the incremental needs of its electric portfolio.[19] Second, PG&E's plan adds renewable generation, to the extent available in the market. If not enough cost-effective renewable generation is available, then PG&E's plan adds, to the extent available, additional renewable generation even if this is not cost-effective in order to meet the existing 20% RPS goal by 2010. Third, the plans include distributed generation available from the recently adopted the CSI program, and historical amounts of non-CSI distributed generation. Finally, and to the extent needed to meet residual capacity and energy needs, the plans add clean, efficient fossil-fueled generation. PG&E's procurement plan also includes transmission additions based on PG&E's Transmission Expansion Plan. These transmission additions are designed to reduce the need for CAISO RMR contracts and to support PG&E meeting the 20% RPS goal.

8. PG&E's Price Forecasting Methodology

a. Gas Price Forecast

PG&E develops its gas price forecast using commodity prices based on the evaluation date closing price of forward contracts traded on the NYMEX exchange plus location basis obtained from broker quotes for gas delivered at AECO, Topock, Malin, San Juan, Rockies and PG&E Citygate for the period through December 2011, which currently marks the end of NYMEX contract availability. For January 2012 and beyond, PG&E extrapolates gas prices using monthly electricity prices through 2015 and maintaining the same monthly relationship between electricity and gas prices as exhibited in the 12 months prior to January 2012. Because broker quotes are not available for 2016 electricity prices, for this long-term plan, PG&E used the gas forecast adopted in the 2005 MPR process starting 2016.[20] The annual price for 2016 is shaped based on the monthly profile observed in 2011.

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[18] EAP II, p. 2.

[19] As indicated in Volume 1, Section IV.D, PG&E has evaluated three candidate procurement plans under four scenarios which represent the uncertainty associated with load, market prices and the availability of resources, including the availability of the State's preferred resources.

[20] Resolution E-3980, Appendix B, 2005 MPR California and Henry Hub Gas Forecast (2006-2031).

PG&E estimates its 95th percentile gas price levels among other risk related metrics using a large number of natural gas and electricity price scenarios in a Monte Carlo simulation. The volatilities and correlations for these simulations are obtained from broker provided and historical data.

b. Electricity Price Forecast

PG&E develops its electric price forecast by using electricity forward prices based on the evaluation date. Broker quotes currently extend out to 2015, and are collected and verified by PG&E's Risk Management Department. Beyond the first few near-term months, quotes are often quarterly or annual. PG&E uses these quotes to construct forward curves that are hourly in resolution. These electricity forward curves are then used by PG&E in its procurement activities (such as the solicitation for long-term resources), as well as for planning purposes. For this long-term plan, 2016 electricity prices are developed using the MPR gas price forecast for 2016, maintaining the same monthly relationship between electricity and gas prices as exhibited in 2011.

PG&E estimates its 95th percentile electricity price levels among other risk related metrics using a large number of natural gas and electricity price scenarios in a Monte Carlo simulation. The volatilities and correlations for these simulations are obtained from broker provided and historical data.

9. PG&E's Hedging Strategy

PG&E's gas and electric hedging strategies for its electric portfolio, including execution strategy and timing, are described in detail in Volume 1, Section III.B and Volume 1, Attachment IIIA.

10. PG&E's Use of the PRG Process

PG&E consults with the PRG on a wide range of transactions generally on a monthly basis (approximately 10 meetings/year). The Commission directed PG&E to consult with the PRG for specific types of transactions including: (1) overall interim procurement strategy; (2) proposed procurement contracts before the contracts are submitted to the Commission for expedited review; and (3) proposed procurement processes including but not limited to RFOs which result in contracts being entered into in compliance with the terms of the RFO.[21] Although the PRG acts in an

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[21] D.02-08-071 at 24.

advisory capacity only, PG&E actively solicits feedback from PRG members and incorporates that feedback into its procurement processes regularly. In particular, PG&E confers with the PRG on:

- **Procurement Plans and Customer Risk Tolerance:** PG&E provides the PRG regular updates of its portfolio position and risk. When the portfolio risk (measured at the 99th percentile) exceeds 125% of the customer risk tolerance ("CRT"), PG&E meets and confers with the PRG to discuss the underlying risk drivers and factors affecting the change in portfolio risk and to decide whether specific hedging strategies and/or plan modifications are needed to reduce portfolio risk to within the CRT threshold.

- **Transactions That Begin More Than 3 Months Out, or Are More Than 3 Months in Length (D.04-01-050):** Currently, PG&E consults with the PRG at least once, and sometimes several times, on transactions greater than three months in length. PG&E discusses how transactions meet portfolio needs, solicitation processes, evaluation methods, negotiation processes and contract selection. As described in Volume 2, Section II.A.1, in the 2006 LTPP, PG&E is requesting that PRG consultation only be required for transactions (including negotiated bilateral agreements) with delivery beginning greater than six calendar months or 2 quarters forward, or a term greater than six calendar months or 2 quarters forward (*i.e.*, increased from the current 3-month/3-month requirement). This will allow PG&E to act more quickly in response to market conditions, and will allow the PRG to focus on the transactions with the greatest impact on customers.

- **LTRFO Design and Administration (D.04-12-048):** PG&E discusses both all-source and renewable RFOs with the PRG. Consultation with the PRG may encompass RFO design, the evaluation processes, short-list selection, negotiation strategy, and bid selection. For the 2004 LTRFO, PG&E consulted with the PRG at least 15 times.

- **Gas Hedging Plans:** PG&E consults with the PRG before filing its DWR gas supply plans. PG&E also consulted with the PRG prior to presenting its Utility Gas Hedging Plans to the Commission for approval.

- **Participation in a Generator Request for Bids (D.04-01-050):** PG&E consults with the PRG prior to making an offer in other Load-Serving Entity ("LSE") solicitations or generator requests for bids.

PG&E also takes advantage of the interactive nature of the PRG process to discuss a wide range of topics that it is not required to discuss with the PRG. For example, shortly after PG&E filed its 2004 LTPP, PG&E provided detailed briefing on the voluminous material in the long-term plan. PG&E has also provided educational sessions to the PRG on topics including credit, market valuation and portfolio fit, risk management and TeVaR, and the principles and processes of gas hedging.

PG&E finds regular consultation with the PRG improves PG&E's and the PRG's understanding of the issues, enhances communication between the parties, and enhances the ultimate procurement decision-making process. Due to PG&E's ongoing dialogue with the PRG, PRG members have the opportunity to learn about challenges the utility faces contemporaneously, rather than hearing about them after the decisions have been made and submitted for Commission approval. PG&E also benefits from the PRG process because PRG members can advise utilities of potentially contentious issues or procurement activities prior to the utility executing a transaction. PG&E supports continuation of the PRG process, and thinks the Commission finding from D.03-12-062 is still relevant:

> Though it only has consultative and informal advisory functions, the Commission finds the PRG to be an effective vehicle for IOU dialogue with Commission staff familiar with the nuances of their energy portfolios and the necessary policies/strategies needed to mitigate portfolio risks. The PRG has played a valuable role in identifying potential issues or concerns regarding IOU procurement. Perhaps the most significant achievement of the PRG process since its inception is the reduction of contested or litigated procurement transactions.[22]

11. Procurement Challenges and Barriers

The Commission and Energy Division have made significant progress in eliminating procurement barriers since the utilities assumed procurement on January 1, 2003. As evidenced by the robust initial response in PG&E's 2004 LTRFO, PG&E does not believe that any significant barriers exist to long-term

[22] D.03-12-062 at 46.

procurement. Specifically, PG&E received a large number of offers from well-qualified companies. PG&E's deposit and credit requirements struck a good balance between ensuring that there were a sufficient number of participants and that individual bidders were provided sufficient incentive to commit to their bid and project through the selection process.

Nevertheless, certain challenges remain. The following list contains examples of barriers, challenges or uncertainties PG&E (and other IOUs) may face when entering into contracts with new or existing resources.

- **Cost Recovery:** PG&E looks for reasonable assurances it will be able to recover its costs of procurement contracts or the costs of ownership over the life of those contracts or facilities. If PG&E does not have a reasonable assurance at the time it considers entering into a PPA or utility ownership contract that it will recover all of its reasonably incurred costs, PG&E will be less inclined to make the resource commitments.

- **Cost Allocation:** To the extent customers are able to avoid paying for their fair share of those contracts by choosing other suppliers or via self-generation, PG&E's risk profile increases and PG&E is less inclined to enter into agreements with new or existing resources.

- **Cost Cap and 50/50 Sharing:** The cost cap and 50/50 sharing mechanism adopted by the Commission in D.04-12-048 creates an unlevel playing field for utility-owned generation and may create a barrier to utility-owned projects. The Commission has established a separate phase in this proceeding to address the cost cap and 50/50 sharing issues. PG&E intends to address the barriers created by the cost cap and 50/50 sharing mechanism in that separate phase.

- **GHG Standards:** The evolution of GHG standards and regulation is an uncertainty which will present a set of additional considerations for PG&E as it contracts with fossil-fired resources, by monetizing the carbon emissions from the facilities or by requiring offsets to the carbon emissions. The use of an adder in evaluation is not a barrier, simply a consideration to assess the relative value of competing projects. Subject to implementing rules (*e.g.*, cap and trade), PG&E does not view the eventual institution of a GHG cap to be a barrier.

- **Counterparty Risk:** When evaluating procurement transactions PG&E considers the financial strength and commercial capabilities of parties offering procurement contracts. Entering into contracts with risky counterparties can increase PG&E's financial risk profile or increase the risk that the resource will not be there when PG&E needs it.
- **Transmission:** PG&E wants to be sure the power contracted for will be delivered where it needs the power. Lack of adequate transmission can be a barrier to contracting with a resource. In its 2004 LTRFO, PG&E required bidders to demonstrate firm physical delivery to NP15 and required bidders to obtain SIS and FS studies from the CAISO.
- **Operating Characteristics:** PG&E and the CAISO need enough peaking and shaping resources across the ISO grid to reliably follow load and respond to resource outages. Resources that cannot provide operational flexibility will be less desirable to PG&E if it is specifically looking to fill those requirements.
- **Permitting:** Problems with permitting a new resource, or retaining or renewing permits for an existing resource, can adversely affect project financing and operations.
- **RA Rules:** RA rules can become a factor to contracting with a resource if that resource's capacity cannot be counted toward RA, or there is uncertainty as to their RA value.
- **MRTU:** The locational marginal costs ultimately adopted in the CAISO's MRTU will encourage LSEs to contract with resources located in low marginal cost nodes and will discourage contracts with resources located in high marginal cost nodes.
- **RPS Terms and Conditions:** The Commission has specified certain standard Terms and Conditions for RPS contracts and has specified that those Terms and Conditions are non-modifiable. This has led to difficulties in

negotiating RPS contracts and concerns among developers. PG&E needs the flexibility in RPS negotiations to modify the Standard Terms and Conditions in appropriate circumstances. PG&E has raised this concern in R.06-05-027 and requested expedited consideration of the issue in that proceeding.

B. Risk Management Policy and Strategy

1. PG&E's Current Risk Management Practices

This section describes PG&E's current electric portfolio risk management practices. PG&E's electric portfolio risk management has evolved over time. PG&E's 2004 Short-Term Procurement Plan ("STPP") set out how the financial risks associated with the electric portfolio's open positions would be managed, including electric and gas price risks.[23] In mid-2005, PG&E formally expanded its price risk management process specifically for the gas component (*e.g.*, electric fuels) of the electric portfolio by implementing a gas hedging program [redacted].[24] This section provides an overview of PG&E's risk management practices. In its 2006 LTPP, PG&E is proposing additional price and physical risk strategies to augment its current practices.

a. Short-term Electricity Price Risk

PG&E currently actively manages short-term electricity open positions covering the [redacted] using the process approved in the 2004 STPP. PG&E manages both short and long positions, measured in average megawatts for each monthly subperiod. The open position targets are shown below in Table Vol. 1, IIIB-1.

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[23] D.03-12-062, PG&E 2004 Short-Term Procurement Plan, Chapter 3, Section E.

[24] This gas program was filed and approved by the Commission in September 2005, and has been updated twice since that time. As provided for in Resolution E-3951, the updates to the hedging program have been approved by the Director of Energy Division.

TABLE VOL. 1, IIIB-1
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICITY OPEN POSITION OPERATING TARGET RANGE
[redacted]

Line No.	Operating Target	[redacted]	[redacted]	[redacted]
1	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]

When open positions fall outside the target range, PG&E will generally bring the position within the target range by executing transactions [redacted]

Even by managing the portfolio within operating targets, there can be events that either cause the net open position to go beyond the operating target range immediately, or have the potential to cause large deviations from the operating target range within the short-term horizon. Examples of such events are extended force outages of major resources, major market disruptions, adverse hydro precipitation conditions and defaulting contracts. In such cases, [redacted]

As part of the 2006 LTPP, PG&E is seeking to modify the term of its current electric open position operating targets so that they are consistent with the gas operating targets. This will make the management of the electricity open position consistent with management of the gas open position, as discussed in more detail in Volume 1, Section III.B.3.

[redacted]

b. Gas Price Risk

PG&E actively manages the gas position of the electric portfolio [redacted] PG&E's initial gas price risk hedging authority was approved in the 2004 STPP. In early 2005, PG&E [redacted] developed and implemented an expanded gas hedging plan. [redacted] The current gas operating targets are shown in Table Vol. 1, IIIB-2. The manner in which these targets are developed, re-evaluated and updated is discussed in Volume 1, Section III.B.3 below. The gas hedging strategy is currently under periodic Energy Division review that began in mid-2005 through an Advice Letter review process.[26]

TABLE VOL. 1, IIIB-2
PACIFIC GAS AND ELECTRIC COMPANY
GAS OPERATING TARGETS [redacted]
(PERCENT HEDGED)

Line No.	Operating Target	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As with the electric position, there can be events that either cause the gas open positions to go beyond operating targets immediately, or have the potential to cause large deviations from the operating targets within the short-term horizon. Examples of such events are addition of non-gas resources to the portfolio, major market disruptions, and above normal hydro conditions. In such cases [redacted]

[26] This gas program was filed July 15, 2005 (AL 2685-E) and approved by the Commission on September 22, 2005 (Res. E-3951), and has been updated twice since that time (AL 2723-E and AL 2775-E). As provided for in Resolution E-3951, these updates to the hedging program have been approved by the Director of the Commission's Energy Division. When the 2006 LTPP is approved, a separate gas hedging plan will no longer be necessary as this will be encompassed within this Procurement Plan.

[redacted]

As part of the 2006 LTPP, these current practices are being augmented with the creation of longer-term electric open position operating targets that are consistent with the gas operating targets. This makes the management of the electricity open position consistent with management of gas open position. This is also discussed in more detail in Volume 1, Section III.B.3.

c. Considerations for Physical Supply Risk

[redacted] The purpose of the long-term gas strategy is to address longer-term physical gas objectives.

Similarly, there are a few physical supply requirements related to electricity. The first is the month-ahead requirement for at least 95% of the forecast load over the month to be physically covered by resources and contracts. Another physical requirement stems from RA requirements. While not requiring availability of resources to the utility, maintaining RA levels ensures sufficient contingency for the CAISO that it will have resources to dispatch to meet load under the vast majority of situations. [redacted]

2. Portfolio Risk Assessment and Customer Risk Tolerance

PG&E's ability to manage its open position exposure in electricity and gas are affected by numerous risks, including: price, market liquidity, model, and credit.

First, with regard to price risk, to the extent that electric and gas commodity prices rise or become more volatile, it makes managing financial exposure more difficult, requiring greater portions of the portfolio to be forward hedged in order to

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[redacted]

prevent potential large movements in future electric portfolio costs. Among the challenges are balancing how much to hedge, when to hedge and what products to use to hedge the exposures.

Second, PG&E faces market liquidity risk. Depending on the quantity of forward hedging and the hedge products desired, prices could move when the hedging is being implemented. When there is lack of market depth, this movement could be significant. One way to mitigate that risk is to establish hedge strategies whereby desired hedging quantities and execution timing are unlikely to cause this to happen.

Third, PG&E can be affected by model risk. Model risk relates to the risks involved in using models to value and hedge assets and commodities. Often, PG&E's portfolio positions are not directly traded in any marketplace. In this situation, models are used to estimate value, select hedging targets, and measure portfolio risk. Included in this is the risk of estimating, extrapolating, or forecasting inputs needed for portfolio evaluation: energy demand, hydro supply, forward prices, volatilities, and correlations. Model risk is addressed by performing sensitivity studies and the development of robust hedging strategies.

Finally, PG&E can be affected by credit risk. Since returning to procurement, PG&E's credit department has employed a credit policy whereby all transactions with counterparties are subject to term and volume limits. Generally, these limits are based on collateral thresholds, credit ratings, and the policies that other companies have agreed to in posting to minimize credit risk, which is another form of financial risk of the electric portfolio. This is another means of controlling the financial risk of the electric portfolio.

[redacted]

Currently, PG&E is required to report its electric portfolio TeVaR to the Commission. PG&E measures TeVaR as the potential change in portfolio costs under a low probability (1%) outcome. It reflects a potential (large) cost outcome over the next 12-month period relative to the mean cost. This cost assumes that no further forward hedging is performed, and that all existing positions are taken to delivery. The TeVaR reporting level is set at 1.25 times a one cent per kWh impact to retail rates, which over the prompt 12-month period is approximately [redacted]

To further manage its portfolio risk, PG&E established as part of its procurement practice operating targets [redacted] While the TeVaR exposure of the electric portfolio has yet to reach this level, it has gotten quite close recently [redacted] given the high market volatilities.

This is the current Procurement Plan or regulatory measure that is tied to guidelines for managing portfolio risk There are other Procurement Plan principles, such as the 95% of total load being covered in the prompt month, but that is more of a physical requirement because it has nothing to do with open position coverage, but rather having the physical capability to meet on a planning basis at least 95% of the expected load for the upcoming month.

3. Electric and Gas Portfolio Hedging Targets

In Volume 1, Section III.B.1, PG&E described its current risk management practices, including an overview of its current electric and gas hedging targets. In the 2006 LTPP, PG&E expands on its current practices by proposing a more comprehensive risk strategy that integrates both the electricity and gas components of the electric portfolio. As a part of this proceeding, PG&E requests that the Commission approve this expanded hedging program, including both its gas hedging program and the complementary electricity hedging program. The remainder of the portfolio hedging discussion is contained in Attachment IIIA.

4. PG&E's Credit and Collateral Requirements

The Commission has not established specific rules for customer risk that apply to credit. PG&E's credit and collateral requirements evolved from accepted energy industry practices, including concepts that can be found in EEI, NAESB, and ISDA master agreements. The primary elements of PG&E's credit and collateral requirements include: collateral thresholds (unsecured credit lines), collateral posting for sales of gas and power, and mark to market posting to cover the change in value of the contract relative to the market. The general goal is to protect the customer against the risk of default by parties (“counterparties”) with whom PG&E enters into wholesale commodity transactions or hedging transactions. PG&E’s credit risk management process includes: creditworthiness evaluations, collateral requirements for various types of transactions, and the level of collateral authority. Each of the aspects of the credit risk management is described below:

- **Creditworthiness**: PG&E manages the credit risk regarding its counterparties by assigning unsecured credit limits or unsecured credit thresholds to them based on PG&E’s assessment of their financial condition, market and industry position, industry volatility and outlook, credit standing, and other credit criteria, as deemed appropriate. PG&E periodically reviews the assigned unsecured credit limits to assess their appropriateness in relation to the then-current credit quality of the counterparty.

- **Counterparty Collateral Requirements**: If a counterparty is a rated entity (*e.g.*, the debt of the entity is rated by S&P, Moody’s or Fitch) assigned a credit rating below investment grade (for example investment grade is considered BBB- or above by S&P or Baa3 by Moody’s) or is a “non-rated entity” not considered creditworthy by PG&E, then PG&E generally will require the counterparty to provide acceptable credit support. Such credit support can be in the form of a cash deposit, guaranty from an investment grade entity, or a letter of credit from an acceptable credit support provider, in form and substance satisfactory to PG&E. For creditworthy counterparties, PG&E establishes a specified unsecured credit limit beyond which posting of acceptable credit support is required. Some of the specific collateral requirements that apply to various categories of transactions are described below.

  Renewable Contracts (New) – Renewable counterparties are required to post a bid deposit of $3 per kW; a development and construction period deposit of $20 per kW; and 6, 9, or 12 months of expected revenue (for 10, 15, and 20 year terms) once commercial operations begin.

Resource Adequacy (RA) – Resource adequacy counterparties (rated as non-investment grade) are generally required to post 25% to 33% of annual capacity payments particularly when RA is a clearly identified component.

Intermediate Term Tolling, Forward or Option Contracts – Intermediate term tolling counterparties are subject to mark to market posting (this amount is generally capped). In addition if the counterparty is below investment grade or is unrated, it may be required to post an independent amount.[28]

Long-Term Tolling Contracts (New) – Long-term tolling counterparties are required to post a bid deposit of $5 per kW; a developmental and construction period deposit of $60 per kW; and once commercial operations begin the counterparty is subject to mark to market posting (this amount is capped and the cap depends on the technology).

Short-Term Transactions – Short-term transactions include hour-ahead, day-ahead, balance of the month, multi-month, and swing deals. Exposures from purchases and sales of power and gas are tracked daily. Collateral requirements are governed by the master agreements under which these transactions are executed.

- **IOU Collateral Authority** – D.04-10-037 grants PG&E, among other things, authority to issue up to $2.5 billion[29] of short-term debt, subject to the restriction that $500 million of that authority may only be used for the following purposes:
  - Procuring natural gas for PG&E's customers during price spikes.[30]
  - Procuring electricity for PG&E's customers during price spikes.

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[28] An independent amount is a flat amount of collateral posted to cover market movements between collateral calls. If the counterparty defaults in between collateral calls (collateral calls typically are made daily or weekly) and fails to post the required margin, the utility can use the independent amount to cover some or the entire shortfall.

[29] On November 9, 2006, the Commission approved PG&E's petition to modify D.04-10-037, granting PG&E requested authority to issue up to $2.5 billion of short-term debt.

[30] D.04-10-037 defines the commencement of a "price spike" as an increase in the price of gas or electricity of at least 50% over the average of the preceding 12 months.

- – Responding to major natural disasters, large scale terrorist attacks, or other cataclysms.

- – Providing liquidity during a major disruption of PG&E's ability to bill, collect, and/or process utility customer bills.

Given these restrictions, PG&E effectively has $2.0 billion of general short-term debt authority, with the additional $500 million of authorization reserved for the foregoing specified contingencies.

C. Fuel Supply Procurement Strategy

1. Natural Gas Procurement Needs and Strategies

In order to meet the growing natural gas needs for PG&E's portfolio of gas generation and tolling agreements, PG&E is proposing the development of a portfolio of gas assets in 2007. PG&E's forecast need for natural gas is based on the generating units and tolling agreements that PG&E must procure gas for. These units and contracts are described fully in Volume 1, Appendix IIIB and summarized in the table below.

TABLE VOL. 1, IIIC-1
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PROCUREMENT GAS-FIRED UNITS AND TOLLING AGREEMENTS

Line No.	Unit Name	Portfolio
1	Bullard	PG&E Tolling Agreement
2	Humboldt Replacement	PG&E Owned
3	Calpeak Firebaugh	PG&E Tolling Agreement
4	Cinergy Firebaugh	PG&E Tolling Agreement
5	PG&E Colusa	PG&E Owned
6	Generic Combined Cycle	Generic Model
7	Generic Combustion Turbine	Generic Model
8	Calpine Russell City	PG&E Tolling Agreement
9	PG&E Contra Costa 8	PG&E Owned
10	Generic Shaping	Generic Model
11	Hayward Black Hills	PG&E Tolling Agreement
12	Humboldt Bay (existing)	PG&E Owned
13	Calpine 3	CDWR Tolling Agreement
14	Calpeak Panoche	CDWR Tolling Agreement
15	Calpeak Vaca Dixon	CDWR Tolling Agreement
16	GWF I (Hanford) and II (Henrietta)	CDWR Tolling Agreement
17	GWF III (Tracy)	CDWR Tolling Agreement
18	PPM Klamath Falls	CDWR Tolling Agreement
19	Wellhead Gates	CDWR Tolling Agreement
20	Wellhead Panoche	CDWR Tolling Agreement
21	Mirant Contra Costa 6	PG&E Tolling Agreement
22	Mirant Contra Costa 7	PG&E Tolling Agreement
23	Mirant Pittsburgh 5	PG&E Tolling Agreement
24	Mirant Pittsburgh 6	PG&E Tolling Agreement
25	Morro Bay 3	PG&E Tolling Agreement
26	Morro Bay 4	PG&E Tolling Agreement
27	Mirant Pittsburgh 7	PG&E Tolling Agreement
28	Kings River Conservation District	CDWR Tolling Agreement
29	Wellhead Fresno	CDWR Tolling Agreement
30	Moss Landing 6	PG&E Tolling Agreement
31	Moss Landing 7	PG&E Tolling Agreement
32	Open from Existing	Generic Model

In order to satisfy these needs, PG&E has developed a gas supply plan. PG&E’s Gas Supply Plan is described in confidential Attachment IIIB.

2. Nuclear Fuel Procurement Needs and Strategies

In addition to strategies for natural gas procurement, PG&E is also proposing a nuclear fuel procurement plan in the 2006 LTPP. In order to support the ongoing operation of DCPP, PG&E purchases nuclear fuel materials. The requirements for each cycle of operation are determined by the length of the cycle. Nuclear fuel consists of four elements: uranium, conversion services, enrichment services and fabrication. PG&E contracts for all four of these elements to produce nuclear fuel specific to the requirements of DCPP.

PG&E's proposed nuclear fuel procurement plan includes a nuclear fuel materials and services procurement strategy for the period 2007 through 2016. The nuclear fuel plan identifies the total quantity of fuel materials and services that are required to support ongoing operation of Diablo Canyon and the quantity distribution over the period 2007 through 2016. PG&E's plan also includes a proposal for establishing a strategic inventory ("SI") of final enriched uranium product to mitigate risk of supplier non-delivery or acts of Force Majeure, and includes measures to manage price and credit risk. The results of PG&E's proposed nuclear fuel procurement plan will be reviewed annually for compliance through the ongoing Energy Resource Recovery Account ("ERRA") proceedings. PG&E's Nuclear Fuel Procurement Plan is confidential and is contained in Attachment IIIC.

PACIFIC GAS AND ELECTRIC COMPANY
VOLUME I, SECTION III – ATTACHMENT IIIA
PG&E'S ELECTRICITY AND GAS PORTFOLIO HEDGING PLAN

CONFIDENTIAL ATTACHMENT

REDACTED IN ITS ENTIRETY

UNDER PROTECTIONS OF D.06-06-066

AND

CPUC CODE SECTION 583

PACIFIC GAS AND ELECTRIC COMPANY
VOLUME I, SECTION III – ATTACHMENT IIIB
PG&E'S GAS SUPPLY PLAN

CONFIDENTIAL ATTACHMENT

REDACTED IN ITS ENTIRETY

UNDER PROTECTIONS OF D.06-06-066

AND

CPUC CODE SECTION 583

PACIFIC GAS AND ELECTRIC COMPANY
VOLUME I, SECTION III – ATTACHMENT IIIC
NUCLEAR FUEL PROCUREMENT PLAN

CONFIDENTIAL ATTACHMENT

REDACTED IN ITS ENTIRETY

UNDER PROTECTIONS OF D.06-06-066

AND

CPUC CODE SECTION 583

PACIFIC GAS AND ELECTRIC COMPANY

VOLUME 1 – 2006 LONG-TERM PROCUREMENT PLAN

SECTION IV – LONG-TERM PROCUREMENT RESOURCE PLAN

2007-2016

PACIFIC GAS AND ELECTRIC COMPANY
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IV. LONG-TERM PROCUREMENT RESOURCE PLAN 2007-2016

A. Introduction to Resource Planning and Planning Approach

In this section, Pacific Gas and Electric Company ("PG&E") describes the framework that it used to develop, analyze and select its recommended 2006 Long-Term Procurement Plan ("LTPP"). In developing its planning framework, PG&E considered the plans of PacifiCorp and Puget Sound, which the December 2, 2005 Assigned Commissioner Ruling ("ACR") mentioned as examples of integrated resource planning.[1] Following these examples, PG&E developed an analytical approach that identifies candidate plans, uses a number of scenarios to test performance of the candidate plans, and selects a recommended plan. As explained in subsequent sections, the recommended plan is a robust plan, and performs well compared to the other candidate plans across all scenarios based on metrics that include reliability, the State Loading Order, cost, price risk, and carbon emissions.

PG&E's analytical framework is composed of three main elements: scenarios, candidate plans and metrics, each of which is described in detail below.

1. Scenarios

The scenarios are combinations of uncertainties affecting PG&E's procurement activities. PG&E segments uncertainties into three categories. The first category is short-term cyclical uncertainties, typically represented by assigning probabilities to different outcomes or impacts. The other two categories of uncertainties are long-term structural and commercial uncertainties. These uncertainties represent different future events and circumstances which are beyond PG&E's control.

a. Short-term Cyclical Uncertainties

Short-term cyclical uncertainties include: weather, hydro conditions, and resource forced outages. These uncertainties result in values that can be higher or lower than their expected value. For example, hydro conditions can be dryer or

[1] *Assigned Commissioner's Ruling*, R.04-04-003, issued December 2, 2005 at 9.

wetter than average. PG&E also includes in this group of uncertainties the price volatility of market prices for natural gas and electricity. Short-term cyclical uncertainties are partially covered by planning reserves. For example, the Western Electricity Coordinating Council ("WECC") Minimum Operating Reliability Criteria ("MORC") includes regulating reserve to continually match loads and resources and a contingency reserve at least equal to the single largest generation or transmission forced outages. Short-term uncertainties are represented probabilistically to estimate the price risk associated with each candidate plan.

b. Long-Term Structural Uncertainties

Long-term structural uncertainties are not covered by planning reserves and include:

- Long-term load growth;
- Direct access ("DA") customers return or departure;
- Potential Community Choice Aggregation ("CCA") departure and core/non-core market penetration;
- Structural changes in market prices;
- Market availability of Customer Energy Efficiency ("CEE"), Demand Response ("DR"), renewables and Distributed Generation ("DG"); and
- Changes in Resource Adequacy ("RA") rules which change the RA value of resources and the utility's procurement need.

c. Long-Term Commercial Uncertainties

Long-term commercial uncertainties are also not covered by planning reserves and include:

- New generation lead times;
- Project permitting execution risk, including delays and inability to obtain all required permits;
- Project construction execution risk, including delays or project failures; and
- Timely regulatory approval of new generation or transmission projects.

These uncertainties have outcomes that are skewed on the side of less than expected levels of generation being available, or delays in commercial operation dates of new resources, and are best represented using scenarios.

d. Scenarios Used By PG&E in the 2006 LTPP.

Taking into account the above long-term structural and commercial uncertainties, PG&E developed four scenarios to represent the conditions that its candidate procurement plans will be exposed to over the next 10 years. Each scenario represents a collection of events, out of PG&E's control, which have a particular effect or stress condition.

Scenario 1 exposes PG&E's portfolio to stranded cost conditions. These conditions are triggered by low market prices and low demand for electricity. If market prices are below the average generation cost of PG&E's portfolio, customers are more likely to exercise CCA and DA options, and more of the expiring resources currently under contract with PG&E are likely to sign with DA and CCA suppliers. In addition, because of low market prices, less preferred resources are available in the market.

Scenarios 2 and 3 represent forward market prices and current demand growth outlook. The main difference between these two scenarios is the level of preferred resources available in the market.

Scenario 4 is characterized by high market prices and high demand conditions. In this scenario, customers are less likely to exercise CCA and direct access options, and consequently less of the expiring resources currently under contract with PG&E are likely to sign with DA and CCA suppliers. Because of high market prices, more preferred resources are available in the market compared to the other three scenarios.

A summary of the key elements of each scenario is presented below.

TABLE VOL. 1, IVA-1
PACIFIC GAS AND ELECTRIC COMPANY
PLANNING SCENARIOS

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Stranded Cost	Current World Low preferred resources availability	Current World Adequate preferred resources availability	High Price/High Growth Scenario
Region Related				
Long-term load growth	Low IEPR Low Growth Rate	High IEPR Growth Rate	High IEPR Growth Rate	Historic long-term growth (2%)
Structural changes in market prices - Gas Prices	Low market Prices	Forward Curves	Forward Curves	Sustained High Prices
Market availability of CEE	Based on supply curve	Based on supply curve for current load/prices	Same as Scenario 2	Based on supply curve for high load/prices
Market availability of renewables	Based on supply curve	Based on supply curve for current load/prices	Same as Scenario 2	Based on supply curve for high load/prices
Market availability of DG-PV	Historic penetration rates	Historic penetration rates plus 50%, capped by CPUC estimate in D.01-06-024	Historic penetration rates plus 50% plus 5% per year, capped by CPUC estimate in D.01-06-024	CPUC Staff estimate in D.01-06-024
Market availability of DR - Large Customer DR	Low customer response	Low customer response	High customer response	High customer response
Market availability of DR - Small Customer DR (AMI)	Low customer response	Low customer response	Base customer response	Base customer response
LTRFO Delays	On time	On time	On time	Delay
Existing fossil retirements	Later	Later	CEC 2012 target	CEC 2012 target
RA Qualifying Capacity Uncertainty	0	500MW less RA value	0	500MW less RA value

Additional Portfolio Related

DA/ Non-Core	DA stays DA	DA stays DA	DA stays DA	DA comes back
CCA	Some CCA departs	No CCA departure	No CCA departure	No CCA departure
RPS QF Recontracting	33%	75%	75%	100%
IDWA Recontracting	50%	80%	80%	100%
Existing Bilateral RPS Contracts	0%	50%	50%	100%

2. Candidate Plans

The candidate plans are alternative combinations of PG&E actions that PG&E considered. The plans include alternative demand-side, supply–side and transmission actions. PG&E tested three candidate plans in preparing the 2006 LTPP. PG&E's

candidate plans are designed to highlight trade-offs between reliability, environmental stewardship, and cost. In the 2006 LTPP, PG&E presents three plans: its recommended plan and two alternative plans that were considered. All three plans are described in Volume 1, Section IV.G, below.

3. Metrics

Metrics are measures used to determine feasibility and performance of candidate plans. Feasibility metrics are threshold requirements which candidate plans need to meet in order to be feasible, including:

- Minimum reliability measured by the plans being able to satisfy the Commission-adopted RA requirements and meet certain adverse conditions without unserved energy;
- Compliance with the State Loading Order requirements;
- Compliance with the current Renewable Portfolio Standard ("RPS") goals; and
- Operational feasibility, *i.e.* the plans provide sufficient resources with the necessary operating characteristics to fit the system's energy and capacity product needs.

Performance metrics measure the performance of the candidate plans and include:

- Reliability;
- Cost (resulting revenue requirements and customer rates);
- Risk (range of customer cost due to cyclical changes in weather impacts and market price volatility);
- Renewable procurement as a percentage of bundled sales; and
- Greenhouse Gas ("GHG") emission levels.

B. Load Forecast (Demand Forecast)

The following section explains how PG&E developed its load forecast and describes the uncertainties associated with its demand forecast in the 2006 LTPP process, including uncertainties associated with load growth, temperature, non-utility procurement options, and other non-temperature related factors.

1. Load Growth Uncertainty

Table Vol. 1, IVB-1 presents the load growth assumptions for each scenario. All four load forecast scenarios used by PG&E in the 2006 LTPP process begin with the 2007 PG&E load forecast approved by the California Energy Commission ("CEC") in July 2006 for use in PG&E's 2007 RA compliance filing. In order to project load growth for the remainder of the forecast horizon (2008-2016), PG&E used the CEC's 2005 Integrated Energy Policy Report ("IEPR") low-growth case projection for the "stranded cost" scenario (Scenario 1) and the CEC's high-growth case projection for the "current world" scenarios (Scenarios 2 and 3).[2] For the "high growth/high price" scenario (Scenario 4), PG&E used an assumed growth rate 0.3% higher than the CEC's 2005 IEPR high-growth case in order to reflect underlying growth similar to that experienced during a period of rapid economic expansion such as the dot-com/telecom driven expansion of 1995-2000. This methodology for developing the underlying load projections is consistent with the required methodology described in the Scoping Memo.[3]

Because PG&E has more recent information on CEE and self-generation (including CSI) than was available when the 2005 IEPR was produced, the growth rates from the 2005 IEPR could not be used directly in PG&E's development of the load scenarios for the 2006 LTPP. Working with the CEC staff, PG&E first developed an adjustment to the published IEPR growth rates to net out CEE and self-generation effects from the IEPR growth rates. Once this was accomplished, PG&E replaced the IEPR assumptions with respect to CEE and self-generation with updated assumptions. The resulting scenario load growth rates are shown in Table Vol. 1, IVB-1, below.

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[2] PG&E did not use the base load growth from the 2005 IEPR in any of its scenarios because, in PG&E's case, the low-growth and the base growth were not materially different.

[3] Scoping Memo, Attachment A at 13.

TABLE VOL. 1, IVB – 1
PACIFIC GAS AND ELECTRIC COMPANY
SCENARIO LOAD GROWTH ASSUMPTIONS

Load Growth Assumptions for PG&E Service Area Scenarios 1 through 4

		Peak Demand (annual average % change 2007-2016)			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
		Stranded Cost Scenario	Current World Scenario	Current World Scenario	High Growth/ High Price Scenario
Line No.		2005 IEPR Low Growth	2005 IEPR High Growth	2005 IEPR High Growth	2005 IEPR High Growth + 0.3%
1	CEC 2005 IEPR Forecast Growth Rate	1.3%	1.7%	1.7%	
2	CEC 2005 IEPR CEE and Self-Generation Adjustment	0.8%	0.7%	0.7%	
3	Adjusted CEC 2005 IEPR Growth Rate	2.1%	2.4%	2.4%	2.7%

The range of load uncertainty that PG&E presents in this filing expands upon the range of load uncertainty captured in the CEC 2005 IEPR Range of Need Transmittal Report ("CEC Transmittal Report"). The CEC Transmittal Report described only a range of load uncertainty associated with a limited set of economic, demographic and efficiency assumptions, but did not consider uncertainty in load due to varying levels of direct access and/or community choice aggregation or a period of rapid economic growth in the underlying economy. The four PG&E procurement load scenarios reflecting these uncertainties are shown in the Summary Range of Need, Tables Vol. 1, IVAX-2 through IVAX-49.

2. Temperature Effect on Peak Demand Forecast

In the short-term, the greatest uncertainty with respect to the forecast of peak load is due to weather. Temperature conditions at the time of the peak can cause peak loads to swing by as much as +/-1,500 megawatts ("MW") or more in any given year relative to the expected forecast value. In order to assess the effect of various temperature conditions on peak demand PG&E, as required by the Scoping Memo, applied the PG&E Planning Area weather multipliers supplied by the CEC to the 1-in-2 recurrence interval expected value forecast. It should be noted, however, that the weather multipliers, as shown in Table Vol. 1, IVB – 2 below, are updated estimates based on the CEC's analysis of the 2005 summer load and temperature data. They are, therefore, consistent with the CEC's June 2006 forecast update.

The 1-in-2 recurrence interval temperature is chosen in such a way that there is a 50% chance that the observed temperature at the time of the peak in any given year will exceed the assumed temperature used to generate the forecast. The 1-in-5 recurrence interval temperature is chosen in such a way that there is a 20% chance that the observed temperature at the time of the peak in any given year will exceed the assumed temperature used to generate the forecast. Likewise, the 1-in-10 recurrence interval temperature and the 1-in-20 recurrence interval temperature are chosen in such a way that there is a 10% and 5% chance, respectively, of their being exceeded in any given year.

TABLE VOL. 1, IVB – 2
PACIFIC GAS AND ELECTRIC COMPANY
CEC'S UPDATED PG&E WEATHER UNCERTAINTY MULTIPLIERS

Line No.	1-in-5 Multiplier	1-in-10 Multiplier	1-in-20 Multiplier
1	1.025	1.035	1.074

The above table shows that moving from the 1-in-2 recurrence interval for peak temperatures to the 1-in-5 recurrence interval temperature increases the load forecast by 2.5%. Moving from the 1-in-2 recurrence interval temperature to a 1-in-10 recurrence interval temperature increases the load forecast by 3.5%. Moving from the 1-in-2 recurrence interval temperature to a 1-in-20 recurrence interval temperature increases the load forecast by 7.4%.

To put this in perspective, using the CEC's updated weather multipliers as shown in Table Vol. 1, IVB-2, the temperature related forecast uncertainty with respect to a 20,000 MW peak projection is approximately 1,500 MW from the 1-in-2 recurrence interval temperature assumption to the 1-in-20 recurrence interval temperature assumption. This level of temperature related forecast risk was evidenced during July 2006 when loads rose above the 1-in-2 forecast levels by more than 2,000 MW driven by the prevailing extreme heat storm conditions. PG&E's current analysis suggests the summer 2006 heat storm event fell somewhere between a 1-in-30 and a 1-in-40 recurrence interval.

3. Non-Utility Procurement Options

The Scoping Memo explained that the utilities should assume that, for the long-term, they are responsible for the resource planning for DA and CCA loads in their service territories.[4] In response, PG&E developed estimates of regional load for the purpose of regional capacity planning. The Scenarios 1 through 4 load growth rates shown in Table Vol. 1, IVB–1, were also used to derive the projected North of Path-26 ("NP26") loads for the regional capacity need determination described in Volume 1, Section IV.E.

A significant uncertainty with respect to PG&E's procurement portfolio planning is the market acceptance of non-utility procurement portfolio options such as DA and CCA. PG&E has incorporated this uncertainty into its four scenarios as shown in Table Vol. 1, IVB – 3, below.

TABLE VOL. 1, IVB – 3
PACIFIC GAS AND ELECTRIC COMPANY
NON UTILITY PROCUREMENT OPTION ASSUMPTIONS

		Non Utility Procurement Option Assumptions Scenarios 1 through 4			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Line No.		Stranded Cost Scenario	Current World Scenario	Current World Scenario	High Growth/ High Price Scenario
1	DA % of Retail Load	current levels	current levels	current levels	decreases from current levels to 0% by 2012
2	CCA % of Retail Load	Increases from current levels to 10% by 2012	current levels	current levels	current levels

As the above table indicates, DA is assumed to remain at its current level (approximately 8% of energy demand, 5% of peak load) in all scenarios except for Scenario 4 where it is allowed to decrease to zero by 2012. This has a material effect on PG&E's procurement portfolio planning as shown in Tables Vol. 1, IVAX - 2 through IVAX-49. With respect to CCA, PG&E has assumed that CCA remains at its current levels (zero) in all scenarios except for Scenario 1 where it grows from its current level to 10% of retail energy load. This level of change in CCA has a material effect on PG&E's procurement portfolio planning as shown in Tables Vol. 1, IVAX-2 through IVAX-49.

[4] Scoping Memo, Attachment A at 13.

4. Other Non-Temperature Related Inputs to Load Forecast

There are a number of other, non-temperature related, inputs to the load forecast projection that create uncertainty with respect to future load growth. Most notable are projections of PG&E service territory household growth rates, projections of air conditioning saturation rates, projections of underlying commercial and industrial activity in the service territory, and projections of the stock and vintages of the residential and commercial buildings in the service territory as well as the stock and vintages of the electricity using appliances within them. In addition to the uncertainty in load forecasts that result from having to project all these load growth drivers, uncertainty in forecasting also results from the need to estimate the relationship between load growth and each of these drivers based on historic data and making inferences based on those estimated historic relationships into the forecast period. PG&E's preliminary analysis suggests that as much a 1,000-1,500 MW of additional uncertainty can be attributed to these non-weather related forecast assumptions over the forecast horizon.

To put this in perspective, PG&E's preliminary analysis suggests that a reasonable estimate of the 95% percent confidence interval (one-tailed) forecast for peak load, including both temperature and non-temperature related uncertainty is 10% higher than the 1-in-2 recurrence interval expected value forecast.[5]

C. Supply Forecast for Existing or Planned Resources

1. Demand-Side Resources

Demand-side resources include energy efficiency, demand response, and customer self-generation including renewables or distributed generation. The demand-side resource forecasts used in the 2006 LTPP are described below.

a. Customer Energy Efficiency

In accordance with the State Loading Order and Energy Action Plan ("EAP"), energy efficiency ("EE") is first in the loading order in PG&E's procurement portfolio. Throughout the next decade, PG&E will continue to aggressively use EE as a way to minimize increases in electricity and natural gas demand to lower customers'

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[5] This 10% estimate is calculated by using the 1-in-20 recurrence interval temperature uncertainty of 7.4% from Table IV.B - 2 applied to an assumed 20,000 MW peak load which yields approximately 1,500 MW of temperature uncertainty. Assuming that temperature and non-temperature related uncertainty (1,000 MW) are independent risks, the joint probability at the 95% confidence interval is approximately 2,000 MW or 10% of peak load.

procurement costs. In all the scenarios described below, PG&E implements the EAP by pursuing all cost-effective EE.

In Decision ("D.") 04-09-060, the Commission established CEE annual and cumulative savings goals for PG&E from 2006 to 2013. These targets were described as "aggressive" and "stretch"[6] and relied on data sources developed as far back as the mid- to late- 1990s. The basic method for determining the targets was to first estimate the technical potential. Technical potential assumes that the existing stock of energy using equipment is replaced with the most current technically efficient equipment. That technical potential was then reduced to what is economically feasible to replace, using the Commission's approved methodology for cost-effectiveness to determine what is economically feasible. Finally, the maximum achievable estimate of market potential was estimated to be about 90% of the economic potential. The maximum achievable potential for EE programs will always be less than economic potential because, even if 100% of the costs to customers of purchasing an energy-efficient product are paid for through program financial incentives such as rebates, not all customers will respond and install efficient products. That is why the Commission based the targets adopted in D.04-09-060 on maximum achievable potential and not simply technical or economic potential.

The studies relied on in D.04-09-060 did not incorporate the improvements in California State EE standards adopted in 2001, continued standards improvement, or the efficiency measures installed through utility programs through 2004. Thus, the D.04-09-060 targets were developed based on data which in some cases is almost a decade old and did not reflect changes in potential resulting from ongoing EE programs and the efficiency improvement in higher building and appliance standards. As newer data is incorporated, especially the effects of changes in building and appliance standards, the potential for utility EE programs will likely be revised downward. PG&E's assumptions regarding CEE for the 2006-2016 period are discussed below.

(1) Assumptions for 2006-2008 Customer Energy Efficiency Forecast

In D.05-09-043, the Commission approved PG&E's 2006-2008 CEE portfolio plan that over the 3-year period meets or exceeds the Commission's cumulative MW

[6] See D.04-09-060, particularly pages 44 (Finding of Fact 2), and 52 (OP 7).

and kWh savings targets for that time period. In all four 2006 LTPP scenarios, PG&E used the following annual MW and kWh CEE savings approved by the Commission.[7]

TABLE VOL. 1, IVC-1
PACIFIC GAS AND ELECTRIC COMPANY
PG&E'S 2006-2008 PROJECTED ENERGY EFFICIENCY IMPACTS

Line No.		2006	2007	2008	Total
1	Total Annual Electricity Savings (GWh/yr)	677	1,125	1,261	3,063
2	Total Peak Savings (MW)	132	222	258	613

Note: Includes savings from low income EE programs.

Source: PG&E Advice 2704-G-A/2786-E-A, April 17, 2006, Attachment II, Table 1.1: Projected Program Impacts by year.

(2) Assumptions for 2009-2016 Customer Energy Efficiency Forecast

In planning for 2009 to 2016, PG&E has incorporated the MW and kWh targets adopted in D.04-09-060 as forecasts in one of the scenarios used to analyze the various candidate plans. In particular, Scenario 4 reflects 2004-2013 targets adopted in D.04-09-060. Beyond 2013, CEE increases at a rate equal to the 2013 annual targets under this scenario.[8]

Scenarios 1-3 use different CEE forecasts for the 2009-2016 time period. In D.04-09-060, the Commission indicated its intention to update energy savings goals on a regular basis. The potential for EE changes over time as a result of increased adoption of EE measures through successful programs, the introduction of new EE technologies, updated avoided costs, and changing energy and appliance codes and standards. The Commission has initiated the process to update EE savings goals after

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[7] In incorporating EE into the 2006 LTPP scenarios, consistent with how the CEC treats EE in the IEPR, PG&E has included EE as either "committed" or "uncommitted." For resource planning purposes, "committed" EE refers to the 2006-2008 programs that have been approved by the Commission and is treated as a reduction in load. "Uncommitted" EE is EE after 2008 and is treated as a resource.

[8] D.04-09-060 provided that "the energy efficiency savings goals adopted in this proceeding should be fully reflected in the IOUs resource acquisition and procurement plans, so that ratepayers do not procure redundant supply-side resources over the short- or long-term." Thus, PG&E has incorporated these Commission adopted goals into Scenario 4.

2008 in Rulemaking ("R.") 06-04-010.[9] Pending the results of the Commission update of EE targets, the most recent study of EE potential that could form the basis for updated EE savings goals is contained in a report published on May 24, 2006, by Itron Consulting ("*Itron Potential Study*").[10] This report summarizes the findings of three recent studies of EE potential in California.[11]

The *Itron Potential Study* indicates that, based on the factors described in D.04-09-060, the potential for unachieved EE potential through utility programs and competitive procurement after 2008 has decreased since the Commission first established energy savings targets due to EE program activity since the earlier potential studies were completed, largely offset by increased energy efficiency due to changes in the state's building and appliance codes and standards. Since it is unclear at this time how this latest estimate of EE potential for utility CEE will affect updated energy savings targets, PG&E used lower utility CEE forecasts for Scenarios 1-3, and retained the targets adopted in D.04-09-060 in Scenario 4. Thus PG&E's scenarios demonstrate its compliance with D.04-12-048, OP 12, and provide for alternative levels of EE when utility-related EE potential is updated, and as key variables take different values as described in the next section.

(3) 2006-2016 Customer Energy Efficiency Forecast

Each 2006 LTPP scenario represents different assumptions for key variables. Two of these variables have a significant impact on the amount of actual, achievable CEE: economic activity and avoided costs (including natural gas prices). In order to capture the effects of these variables, two EE cases were developed to reflect different levels of economic activity and avoided costs and natural gas prices.

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[9] *See* Attachment to the Administrative Law Judge's Ruling and Notice of Prehearing Conference, dated April 17, 2006, in R.06-04-010 (identifying Phase 4 of the R.06-04-010 as "Updates to EE Potential Studies and Savings Goals" and "Schedule to be developed in late 2006.")

[10] The *Itron Potential Study* was conducted by a team of firms consisting of Itron, Inc. (Itron), KEMA, and Quantum Consulting under the management of PG&E. The study was overseen by a Project Advisory Committee consisting of representatives from PG&E, Southern California Edison Company ("SCE"), Southern California Gas Company, San Diego Gas & Electric Company ("SDG&E"), the Commission, the CEC, and Natural Resources Defense Council.

[11] *California Energy Efficiency Potential Study*, prepared for PG&E by Itron, Inc., Kema Inc., Architectural Energy Corp., and RLW Analytics. May 24, 2006. This report can be obtained at www.calmac.org in the reports library under study ID PGE0211.01.

Current natural gas and electricity market prices, and corresponding avoided costs, were used in Scenarios 2 and 3 to assess EE potential. In terms of EE, while the technical potential is unchanged, the portion of the technical potential that is economic, or cost-effective, is smaller relative to Scenario 4, which has higher load growth, and higher natural gas and energy prices. This means that when PG&E estimates how much EE could be achieved through CEE programs, in this case there is a smaller base of economic EE to pursue. Further, as the overall rate of economic opportunity in Scenarios 2 and 3 is lower compared to Scenario 4, the situations in which a new building can incorporate improved efficiency, or the number of new purchases of equipment that provide an opportunity to raise efficiency are fewer. Overall quantity of the energy efficiency incorporated into Scenarios 2 and 3 is less than that included in LTPP Scenario 4. These effects are magnified in Scenario 1, which has lower levels of economic activity and lower natural gas prices and EE avoided costs than in Scenarios 2 and 3. As a result, the EE included in Scenario 1 is the least of the four LTPP scenarios. The results of these scenarios are shown in Table Vol. 1, IVC-2, below.[12] In all four scenarios, PG&E plans to aggressively pursue all cost-effective EE.

[12] The peak savings figures shown below are based on the definition for peak reduction adopted in D.06-06-063.

TABLE VOL. 1, IVC-2
PACIFIC GAS AND ELECTRIC COMPANY
PG&E TOTAL ELECTRICITY PROGRAM SAVINGS GOALS

Line No.		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Scenario 1 – Stranded Cost											
2	Total Annual Electricity Savings (GWh/yr)	677	1,125	1,261	864	808	764	741	794	782	801	759
3	Total Cumulative Savings(GWh/yr)	677	1,802	3,063	3,927	4,735	5,499	6,240	7,034	7,816	8,617	9,376
4	Total Cumulative Peak Savings (MW)	132	354	613	810	1,003	1,189	1,376	1,570	1,765	1,962	2,149
5												
6	Scenario 2 – Current World – Lower Preferred Resources											
7	Total Annual Electricity Savings (GWh/yr)	677	1,125	1,261	881	833	795	777	836	832	848	831
8	Total Cumulative Savings(GWh/yr)	677	1,802	3,063	3,944	4,777	5,572	6,349	7,185	8,017	8,865	9,696
9	Total Cumulative Peak Savings (MW)	132	354	613	816	1,017	1,212	1,409	1,615	1,822	2,032	2,240
10												
11	Scenario 3 – Current World – Adequate Preferred Resources											
12	Total Annual Electricity Savings (GWh/yr)	677	1,125	1,261	881	833	795	777	836	832	848	831
13	Total Cumulative Savings(GWh/yr)	677	1,802	3,063	3,944	4,777	5,572	6,349	7,185	8,017	8,865	9,696
14	Total Cumulative Peak Savings (MW)	132	354	613	816	1,017	1,212	1,409	1,615	1,822	2,032	2,240
15												
16	Scenario 4 – High Price, High Growth											
17	Total Annual Electricity Savings (GWh/yr)	677	1,125	1,261	1,067	1,015	1,086	1,173	1,277	1,277	1,277	1,277
18	Total Cumulative Savings(GWh/yr)	677	1,802	3,063	4,130	5,145	6,231	7,404	8,681	9,958	11,235	12,512
19	Total Cumulative Peak Savings (MW)	132	354	613	844	1,064	1,300	1,554	1,832	2,110	2,388	2,666

b. Demand Response

In June 2002, the Commission opened R.02-06-001 to create a policymaking forum to develop DR as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. The desired outcome of this effort was a broad spectrum of DR programs and tariff options that would be available to customers.

In D.02-10-062, the Commission instructed the utilities to "consider all cost-effective investment in demand response that meets their procurement needs" in their procurement planning. This decision identified R.02-06-001 as the appropriate venue to establish demand response design strategies and programs to become part of their long-term plans. In D.03-06-032, the Commission adopted a policy for developing DR targets based on price responsiveness rather than reliability.[13] The Commission set annual MW targets to be met through DR and included in investor-owned utility ("IOU") procurement plans. The targets increase in every year and hit a peak of 5% of total bundled load peak in 2007 and subsequent years. That decision also stated that "this goal does not include (is over and above) demand response achieved through the emergency programs."[14] That decision recognized that the price responsive demand targets might not be achieved, and "to the extent that the actual reliable demand response resources fall short of the goals, the utilities should be allowed and able to supplement their short term purchases."[15]

PG&E's DR forecast consists of three separate elements: (1) DR from existing programs; (2) DR from enhancements that PG&E proposed in an August 30, 2006 filing at the Commission and an Air Conditioning ("A/C") Cycling/Load Control program which will be the subject of an application that PG&E intends to make soon; and (3) additional DR from Critical Peak Pricing ("CPP") that results from the deployment of the Advanced Metering Infrastructure ("AMI"). These projections are shown in Table Vol. 1, IVC-3 and Table Vol. 1, IVC-4, below. In developing its A/C Cycling program, PG&E estimates that approximately 1.6 million of its nearly 4.5 million residential customers are equipped with central A/C. Over a 4-year period, an aggressive customer marketing campaign can achieve a market penetration of up to 25%. This penetration rate is consistent with other mature utility air conditioning control programs nationally. This penetration rate results in approximately 305 MW of load relief potential from an A/C Cycling/Load Control Program shown in Table Vol. 1, IVC.3 and Table Vol. 1, IVC.4 below.

PG&E's existing "reliability" DR programs, which include its Non-firm and E-BIP programs, have a long and proven track record of reducing load when it is most needed. The Non-firm program was opened to customers in the early 1990s and has since been a valuable asset to PG&E's resource portfolio. Participants are given a rate discount in exchange for dropping their loads to a pre-determined "firm service level" when given 30 minutes notice by the utility. Participants who do not comply

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[13] D.03-06-032 at 18.

[14] *Id.*at 8.

[15] *Id.* at 10.

with the curtailment order are penalized via a large energy charge on any power used in excess of their contracted amount which in part explains their extremely high compliance rate. The Non-firm program was closed to new customers in 1997 but continued to pay dividends.

During the 2001 energy crisis, the Non-firm program was called so frequently that the annual curtailment limit of 100 hours was reached after the first 22 days of the year. Later that year, a companion program, E-BIP, was created as a new reliability program for customers and one that would allow for additional payments to Non-firm participants if they chose to continue to provide load relief after their own program requirements were exhausted.

In D.05-04-053, the Commission ordered the Non-firm program to be closed and its participants to transition over to the E-BIP program if they desired to continue to participate in reliability demand response. Despite this transition, given an appropriate incentive structure, PG&E is confident that it can retain and grow this very dependable load relief in the future.

PG&E's DR forecast is subject to a number of uncertainties. For example, the actual DR requirements are still subject to an ongoing Commission proceeding. In D.05-11-009, the Commission addressed two important aspects of reliable DR programs—measurement and evaluation and a cost-effectiveness methodology. Well-defined measurement and evaluation protocols are essential to ascertain that desired demand reductions have in fact taken place. In addition, a standardized cost-effectiveness test is necessary ensure that ratepayers are paying appropriate amounts for demand reduction.

In D.06-03-024, the Commission acknowledged that the key elements of measurement and evaluation and cost effectiveness impact the amount of desired DR. Ordering Paragraph 3, requires that "Applications ("A.") 05-06-006, 05-06-008, and 05-06-017 remain open to address program goals and cost-benefit methodologies as discussed herein." As of the date of this filing, the Commission has yet to address measurement and evaluation, cost effectiveness, or revised program goals in light of rigorous measurement and evaluation and cost effectiveness methodologies. Clearly, developments in these areas could impact the amount of actual DR and the goals that PG&E uses for long-term planning.

Given this uncertainty, PG&E has included in its 2006 LTPP its best estimates of reliable demand response. The estimates shown on the tables below reflect actual program experience, PG&E’s efforts to enhance demand response and projected results from AMI implementation. All of these estimates may change over time as a result of Commission action, as well as responses in the market.

The tables below present two scenarios for actual DR programs. As noted above, both scenarios assume the Commission will act favorably on PG&E’s proposed enhancements to DR.[16] The first scenario reflects a “low case” DR from AMI rollout, and is included in Scenarios 1 and 2. The second case is a “base case” DR from AMI implementation, and is included in Scenarios 3 and 4. Both of the AMI response cases are from PG&E’s AMI application (A.05-06-028) and are described in Volume 1, Section V.C.

[16] On October 30, 2006, a Proposed Decision (“PD”) was issued approving only some of the DR program changes submitted in PG&E’s August 30th filing. The PD was approved by Commission as D.06-11-049 on November 30, 2006, reducing PG&E’s proposed DR forecast by approximately 200 MW. PG&E did not have time to reflect the effect of this decision in its 2006 LTPP analysis. However, PG&E has quantified how D.06-11-049 affects its resource need, and the procurement authority it requests in this filing. The reduced DR amounts are also shown in Volume 1, Section V, Table Vol. 1, VC-1.

TABLE VOL. 1, IVC-3
PACIFIC GAS AND ELECTRIC COMPANY
DEMAND RESPONSE PROGRAMS FOR SCENARIOS 1 AND 2
(MW)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Existing Programs										
2	Reliability:										
3	Interruptible/BIP	353	353	353	353	353	353	353	353	353	353
4	Total Reliability	353	353	353	353	353	353	353	353	353	353
5	Price Responsive Programs:										
6	BEC	19	19	19	19	19	19	19	19	19	19
7	CPA-DRP	240	240	240	240	240	240	240	240	240	240
8	Large CPP	21	21	21	21	21	21	21	21	21	21
9	Demand Bidding	22	22	22	22	22	22	22	22	22	22
10	Total Price Responsive	302	302	302	302	302	302	302	302	302	302
11	**Total Existing**	655	655	655	655	655	655	655	655	655	655
12	PG&E Proposed Enhancements as filed on August 30th, 2006										
13	Reliability:										
14	AC Cycling/Load Control	5	105	205	305	305	305	305	305	305	305
15	BIP & Non-firm	70	95	95	95	95	95	95	95	95	95
16	Total Reliability	75	200	300	400	400	400	400	400	400	400
17	Price Responsive Programs:										
18	RFPs & Contracts	35	70	70	70	70	70	70	70	70	70
19	BUGS	50	100	100	100	100	100	100	100	100	100
20	Demand Bidding	25	50	50	50	50	50	50	50	50	50
21	Extended BEC	25	50	50	50	50	50	50	50	50	50
22	Expanded TA/TI and Auto DR	25	50	50	50	50	50	50	50	50	50
23	Total Price Responsive	160	320	320	320	320	320	320	320	320	320
24	**Total Proposed Enhancements**	235	520	620	720	720	720	720	720	720	720
25	AMI/CPP	9	41	114	182	207	214	217	221	228	229

(a) This table provides the amount of demand response expected to be achieved by July 1 of each year. The incremental reductions associated with new or enhanced programs are not counted as meeting RA requirements until the following year based on the program's historical performance. The 2007 amounts reflect the demand response received during the July 2006 heat storm.

TABLE VOL. 1, IVC-4
PACIFIC GAS AND ELECTRIC COMPANY
DEMAND RESPONSE PROGRAMS FOR SCENARIOS 3 AND 4
(MW)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Existing Programs										
2	Reliability:										
3	Interruptible/BIP	353	353	353	353	353	353	353	353	353	353
4	Total Reliability	353	353	353	353	353	353	353	353	353	353
5	Price Responsive Programs:										
6	BEC	19	19	19	19	19	19	19	19	19	19
7	CPA-DRP	240	240	240	240	240	240	240	240	240	240
8	Large CPP	21	21	21	21	21	21	21	21	21	21
9	Demand Bidding	22	22	22	22	22	22	22	22	22	22
10	Total Price Responsive	302	302	302	302	302	302	302	302	302	302
11	**Total Existing**	655	655	655	655	655	655	655	655	655	655
12	PG&E Proposed Enhancements as filed on August 30th, 2006										
13	Reliability:										
14	AC Cycling/Load Control	5	105	205	305	305	305	305	305	305	305
15	BIP & Non-firm	70	95	95	95	95	95	95	95	95	95
16	Total Reliability	75	200	300	400	400	400	400	400	400	400
17	Price Responsive Programs:										
18	RFP's & Contracts	35	70	70	70	70	70	70	70	70	70
19	BUGS	50	100	100	100	100	100	100	100	100	100
20	Demand Bidding	25	50	50	50	50	50	50	50	50	50
21	Extended BEC	25	50	50	50	50	50	50	50	50	50
22	Expanded TA/TI and Auto DR	25	50	20	20	20	20	20	20	20	20
23	Total Price Responsive	160	320	320	320	320	320	320	320	320	320
24	**Total Proposed Enhancements**	235	520	620	720	720	720	720	720	720	720
25	AMI/CPP	9	92	282	393	448	463	472	481	490	499

c. Distributed Generation/Solar Generation

In addition to EE and DR, PG&E also supports distributed and solar generation resources. Distributed generation has been broadly described as "electricity produced on-site or close to a load center that is also interconnected with a utility distribution system."[17] PG&E prefers to address generation designed to serve on-site customer load separately from generation—no matter where located—that is designed largely for export to the grid. Therefore, for purposes of this section, PG&E will address customer generation ("CG"), which is defined as electricity produced on customer sites from generators that are interconnected to the utility distribution system and are

[17] *2005 Integrated Energy Policy Report*, Commission Final Report, Adopted November 21, 2005, Pub # CEC-100-2005-007-CMF, page 76.

designed predominantly to serve the customer's own load (or to provide power to up to two adjacent customers via over-the-fence arrangements).[18]

Customer generation can come in almost any size, ranging from small 1 kilowatt ("kW") solar projects to large 50 MW projects serving industrial loads. Generally, however, customer generation is 10 MW or smaller, and interconnected at the distribution level. The primary motivations for a customer installing generation are the reduction of energy bills and increased efficiency of its operations. Most CG installed by PG&E customers since 2001 has received incentives either through the Self-Generation Incentive Program ("SGIP") or the Emerging Renewables Program administered by the CEC—both of which are funded by PG&E ratepayers. There is also some CG installed by PG&E customers that does not receive incentives.

For long-term planning purposes, PG&E prepared a range of estimates for future solar installations and estimates for customers installing combined heat and power ("CHP") generation and other generation technologies. All estimates are for PG&E's existing and new bundled service customers.[19]

(1) Solar Installations

There is currently some uncertainty surrounding the final design of the California Solar Initiative ("CSI") and there are a variety of factors that could affect the penetration rate at which PG&E is able to implement the CSI. Given the high incentive rates paid over the last several years, solar CG has proven to be extremely popular with PG&E's customers. In both 2004 and 2005, the solar funds available through the SGIP were oversubscribed and PG&E has had a waiting list for the last few years. In 2005, the program received so many applications that a waiting list was created on the first day that applications were accepted. In 2006, even with an additional $118.8 million available for incentives, a waiting list was created from projects "carried forward" from the 2005 waiting list and additional projects received the first day applications were accepted.[20]

[18] Not included in this definition are on-site generators over-sized as to on-site load so as to deliver energy to the grid for sale.

[19] Some bundled service customers receive gas from PG&E and electricity from a publicly-owned utility ("POU"). These customers are included only in the relevant estimates (*e.g.*, CHP, but not photo-voltaic ("PV") estimates).

[20] However, it should be noted that due to drop outs, there is currently not a wait list and there is available funding for solar installations.

Another contributing factor to the high level of interest in the program is the generous tax incentive provided by the federal government for 2006 and 2007. At this time, it is unclear whether that tax incentive will continue beyond 2007, and if so, at what level.

PG&E expects continued interest in solar generation from its customers, but the recent level of activity might not continue at the same pace for several reasons. First, there is a shortage of PV panels available, which is keeping panel costs high in the short term. Second, it is not clear whether the current level of interest will continue as rebates decline if total installation costs do not also decline. The CSI is designed as a market transformation program, with rebates decreasing annually. Increased market penetration is anticipated to lead to lower installation costs, meaning that more customers will participate, even though the incentives are lower. The declining rebates assume declining total installed costs. However, it is not clear whether the current high interest by customers will continue as rebates decline if total installation costs do not also decline.

In addition to the uncertainty caused by rebates, the Commission has established that customers installing units 100 kW or larger will move from a system of incentives based on rated capacity of the CG unit to one based on the unit's performance, called performance based incentives ("PBI"). Many of the details of this shift have yet to be finalized and there is limited research on likely customer reaction and no observed customer behavior on solar CG adoption under PBI. Other changes wrought by the CSI include a commitment of certain funds to low income customers and a commitment to increased research and development. The CSI also anticipates inclusion of other solar technologies, including solar water heating, for customers who currently use electricity to heat their water. Finally, the recent passage of Senate Bill ("SB") 1 means that differences between the CSI and SB 1 provisions must be reconciled—introducing another set of unknowns.

Given the limited research predicting likely customer response under PBI and the lack of knowledge about the impact research and development will have on solar CG costs, there is considerable uncertainty with respect to customer implementation rates. Some of the factors—such as higher funding levels and continued tax incentives—will tend to increase customer participation. Others, such as changes to CSI program design and the shortage of solar panels, will tend to depress solar penetration rates. PG&E believes customers will choose to install solar generation at least as frequently as in the past few years.

Therefore, for 2006 LTPP planning purposes, PG&E has developed four different solar CG estimates for Scenarios 1 though 4. To develop the Scenario 1 estimate, PG&E first calculated the historical installation rate of customer solar generation over the last three years, and then assumed that future installations would continue at this same rate. The resulting estimate used in Scenario 1 is approximately 28 MW[21] and about 42 gigawatt-hours ("GWh") per year for the forecasting period.[22]

In Scenario 2, PG&E's solar CG estimate increased the historic installation rates by 50%, with a ceiling on installations based on the estimate of installation rates contained in D.06-01-024 for both the Commission and the CEC CSI programs. This yielded an estimate that is about 42 MW and about 63 GWh per year for the forecasting period, except for the first year, which hits the ceiling of 33.2 MW and 49.4 GWh.

In Scenario 3, PG&E again used as a ceiling the estimate in D.06-01-024. Thus the first year PG&E used the same estimate as Scenario 2—33.2 MW and 49.4 GWh. For the second year, PG&E used rates that were 50% above the historic forecast, again the same as Scenario 2. However, starting in the third year, PG&E used an additional 5% installation increase above the 50% increase used in Scenario 2. Thus, the increase over the historic rate is 55% in the third year, 60% the fourth year, and so forth. By the last year of the forecast period, the installation rate is 95% above the estimate in Scenario 1.

In Scenario 4, PG&E used two regulatory assumptions. PG&E started with its expected share of the Commission estimate found in D.06-01-024, resulting in 28 MW in 2007 and increasing to 286 MW in 2016.[23] PG&E then added an estimate of the residential new construction solar program to be administered by the CEC, which is estimated to average 11.2 MW per year for the years 2007 through 2011.

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[21] The 28 MW reflects post-inverter capacity.

[22] Installed MWs were converted to GWh using a 20% capacity factor. *See CPUC Self-Generation Incentive Program Fourth-Year Impact Report: Final Report*, Itron, April 15, 2005. In the last few years, the capacity factors calculated by Itron for solar installations funded through the SGIP have ranged from 13.9%-18.7%. This analysis assumed that with PBI and other program changes designed to improve performance, the capacity factor would be higher.

[23] *See* D.06-01-024, Appendix A, Table 5. PG&E's share is 44%.

In all four scenarios, installed MWs were converted to GWh using a 20% capacity factor. The Commission sponsored an impact analysis of the 2004 SGIP performed by Itron, which found capacity factors ranging from 13.9% to 18.7%.[24] PG&E assumed that the CSI program design features, such as the PBI, will increase the capacity factor of the typical installation. The four estimates for installation rates of solar generation by PG&E customers are shown in Table Vol. 1, IVC-5.

(2) CHP Installations Intended Primarily for On-Site Load

To develop its CHP forecast, PG&E first calculated the installation rate of customer CHP generation over the last three years, and assumed that future installations would continue at this same rate. There appears to be continuing regulatory and customer interest in expanding reliance on CHP to meet future energy demand in California. The loading order in EAP II specifically refers to cost-effective CHP as preferable to traditional sources of electricity generation.[25] The CEC has also recently called for increased reliance on CHP.[26] As with solar generation, there are many factors likely to affect customers' choices with respect to CHP CG. Customers' economic evaluation will depend on gas prices, which might fluctuate in the near future and which are certainly higher recently. As a recent CEC-sponsored study pointed out "[g]as costs are the single most important component of CHP operating costs."[27] A second factor affecting customer choice is the impact of air quality regulations.[28]

Some factors will increase the likelihood that customers will install CHP CG—such as inclusion in the loading order of EAP II—and some factors will depress CHP installation such as gas price instability and air quality regulations. There is considerable uncertainty around the extent to which customers have the appropriate

[24] *CPUC Self-Generation Incentive Program Fourth-Year Impact Report: Final Report*, Itron, April 15, 2005. In the last few years, the capacity factors calculated by Itron for solar installations funded through the SGIP have ranged from 13.9%-18.7%.

[25] EAP II at 10-11.

[26] *2005 Integrated Energy Policy Report*, Commission Final Report, Adopted November 21, 2005, Pub # CEC-100-2005-007-CMF, page 80.

[27] *Evaluation of Policy Impacts on the Economic Viability of California-Based Combined Heat and Power from a Project Owner's Perspective*, PIER Final Project Report, CEC-500-2006-068, July 2006.

[28] *The Impact of Air Quality Regulations on Distributed Generation*, NREL/SR-200-31772, October 2002.

combination of electric and thermal loads that make CHP economically feasible and would also choose CHP to meet their energy needs. To date, PG&E has seen no indication that customers are more inclined recently to install CHP than they have been in prior years. Consequently, for all four scenario analyses, PG&E assumed customers would simply continue historic behavior. Unlike solar CG, PG&E has seen no increase in installation of CHP CG, despite legislative and regulatory support. Therefore, for 2006 LTPP planning purposes, PG&E assumed installations will continue at a rate based on recent historic activity. PG&E's cumulative additions of CHP are found in Table Vol. 1, IVC-5.

(3) Other Customer Generation Technologies

Finally, PG&E developed a single forecast for other customer generation technologies for use in all four scenarios. Similar to the forecast for CHP described above, PG&E's forecast for the other technologies was developed by first calculating the installation rates of each technology over the last three years, and then assuming the installation rates for each continued into the future. PG&E's cumulative additions of other customer generation technologies are found in Table Vol. 1, IVC-5.

TABLE VOL. 1, IVC-5
PACIFIC GAS AND ELECTRIC COMPANY
ESTIMATES OF CUSTOMER GENERATION

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1							(MW)				
2	Solar										
3	Installed:										
4	Scenario 1	28	56	84	112	140	168	196	224	252	280
5	Scenario 2	33	75	117	159	201	243	285	327	369	411
6	Scenario 3	33	75	130	191	252	315	380	446	513	581
7	Scenario 4	33	75	130	199	285	386	518	694	914	1,200
8	Available at Peak:										
9	Scenario 1	11	22	33	44	55	66	77	87	98	109
10	Scenario 2	13	29	46	62	79	95	111	128	144	160
11	Scenario 3	13	29	51	74	98	123	148	174	200	227
12	Scenario 4	13	29	51	78	111	151	202	271	357	468
13	CHP										
14	Installed:										
15	All Scenarios	28	57	85	113	142	170	198	226	255	283
16	Other DG										
17	Installed:										
18	All Scenarios	8	17	25	34	42	50	59	67	75	84
19							(GWh)				
20	Solar										
21	Scenario 1	49	98	147	196	245	294	344	393	442	491
22	Scenario 2	58	132	205	279	353	426	500	573	647	721
23	Scenario 3	58	132	229	334	442	552	665	781	898	1,019
24	Scenario 4	58	132	229	348	499	676	908	1,216	1,601	2,102
25	CHP										
26	All Scenarios	176	352	528	704	879	1,055	1,231	1,407	1,583	1,759
27	Other										
28	All Scenarios	52	104	156	208	260	313	365	417	469	521

2. Renewable Energy Resources

The purpose of this section is to describe how renewable energy is integrated in the 2007 through 2016 planning horizon, including the elements of uncertainty which must be accounted for in the plan and PG&E’s progress towards its RPS targets. PG&E’s strategy for renewable energy procurement over the planning horizon is provided in Volume 1, Section V.D. PG&E’s response to the Scoping Memo’s request for comments on a possible expanded RPS goal is addressed in Volume 1, Section V.D and in Volume 2, Section I.B.5.

In accordance with the EAP loading order, renewable energy plays a lead role in PG&E’s supply-side resource procurement portfolio. Throughout the next decade, PG&E will continue to aggressively use renewable energy as the preferred alternative to conventional resources. Therefore, in all the scenarios described below, PG&E is planning to procure all available renewable resources, subject to market and transmission constraints until it meets its RPS targets, even if they are priced above market price. Once PG&E meets its RPS targets, it will implement the EAP loading order by pursuing all cost-effective renewable energy resources as discussed in Volume 1, Sections V.B and VI.

a. Existing Renewable Resources

PG&E received approximately 11.9% of energy delivered in calendar year 2005 from renewable resources. The contribution of these resources over time to PG&E's RPS targets will depend on PG&E's success in renewing contracts with these suppliers when they expire. In its *December 2005 Supplement to its Renewable Energy Procurement Plan*,[29] PG&E provided High, Medium and Low Baseline scenarios in compliance with D.05-10-014. These scenarios represented various renewal rates over the 10-year planning horizon for each category of existing baseline renewable resources: Qualifying Facilities ("QF"), Irrigation District ("ID") contracts and signed renewable projects executed before 2005. PG&E uses the same methodology in the 2006 LTPP as it did in its December 2005 Supplement and updates the baseline with contracts signed to date as discussed below.

PG&E developed four scenarios to, among other things, represent the range of uncertainty of the market availability of renewable energy across the planning horizon. Scenario 1 represents a declining market where the best renewable projects have been developed and other RPS markets are attractive. Under Scenario 1, PG&E assumes that it is unsuccessful at renegotiating most expiring RPS contracts. Under this scenario less than 50% of expiring contracts are estimated to be renewed. Scenarios 2 and 3 are scenarios where the availability of renewables in the marketplace is consistent throughout the planning horizon. Under Scenarios 2 and 3, PG&E assumes that it is fairly successful at renewing its expiring contracts, and there is an assumed percentage of attrition. Under these scenarios the estimated renewal rate for existing contracts averages over 75%. Scenario 4 reflects a situation where a significant number of new renewable resources are available in the market place year to year. Under Scenario 4, PG&E assumes it will be successful at renewing all existing contracts that expire between 2007 and 2016. Scenarios 2-4 assume the use of existing procurement tools, including short-term contracts.

[29] PG&E filed the December 2005 supplemental plan in R.04-04-026.

In addition to assumptions regarding the renewal of QF, ID, and other baseline RPS contracts, PG&E made several assumptions regarding existing RPS resources. First, PG&E made assumptions regarding the renewable contracts entered into by the California Department of Water Resources ("DWR"). Pursuant to D.02-08-071, DWR, on behalf of PG&E, entered into four renewable contracts in December 2002. Three of the contracts totaling 113 MW of nameplate capacity began deliveries in January 2003 and are counted as eligible RPS resources. These contracts were selected through a solicitation process that was submitted for Commission approval on November 15, 2002 and approved via Resolution E-3805.[30] These are 5-year contracts and are scheduled to terminate by the end of 2007, but 110 MW of the 113 MW has since been negotiated into a new contract. If approved by the Commission this new contract will commence in 2007 and continue through 2012, and the capacity under the new contract will be increased to 200 MW of RPS eligible geothermal energy. For purposes of the 2006 LTPP, PG&E has assumed the contract will be approved. The monthly energy forecast is shown on lines 36 and 37 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 38 and 39 of Tables Vol. 1, IVAX-38 through IVAX-49.

Second, PG&E's 2006 LTPP forecasts include RPS contracts already executed by PG&E. In October 2003, PG&E entered into three renewable contracts totaling 43 MW of nameplate capacity that are counted as eligible RPS resources.[31] The monthly energy forecast is shown on lines 38 – 38b of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 40–40b of Tables Vol. 1, IVAX-38 through IVAX-49. On October 7, 2004, PG&E filed Advice Letter 2562-E which requested Commission approval of a new renewable contract with Florida Power and Light Energy Co., LLC. This contract is for the repowering of an existing 18 MW wind facility known as Diablo Winds in the Altamont Pass area of northern California. The Commission approved this contract in Resolution E-3900. Deliveries began in 2005 and are available throughout the planning horizon. The contract is counted as an existing RPS eligible resource. The monthly energy forecast

[30] PG&E assumed the role of purchaser in these contracts and therefore these contracts are reflected as PG&E RPS contracts, rather than being considered DWR contracts in the accompanying energy and capacity tables.

[31] These contracts were submitted for Commission approval on September 18, 2003, and approved via Resolution E-3853.

is shown on line 38c of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on line 40c of Tables Vol. 1, IVAX-38 through IVAX-49.

PG&E has a power purchase contract with Metropolitan Water District ("MWD") for 24 MW of power from the Etiwanda Power Plant. The Etiwanda contract expires in mid-January 2014. This contract is also counted as an existing RPS eligible resource. The monthly energy forecast is shown on line 38d of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 40d of Tables Vol. 1, IVAX-38 through IVAX-49.

In 2005, in response to PG&E's 2004 RPS solicitation, PG&E entered into a number of contracts for existing and future RPS resources. One of these contracts is currently operational. For purposes of this forecast, five others are projected to be operational by the end of 2008. Once operational, the combined nameplate capacity from these contracts will be 311 MW. The monthly energy forecast is shown on lines 38e - 38j of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 40e - 40j of Tables Vol. 1, IVAX-38 through IVAX-49.

PG&E entered into additional contracts resulting from its 2005 RPS solicitation. As of October 31, five contracts are projected to be operational between 2007 and 2010 from the 2005 solicitation with a combined nameplate capacity of 150 MW (additional contracts may result from the 2005 solicitation, but they were filed too late to be included in this analysis). The monthly energy forecast is shown on lines 38k – 38o of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 40k – 40o of Tables Vol. 1, IVAX-38 through IVAX-49.

PG&E recently received bids in its 2006 RPS solicitation in which PG&E would enter into agreements to purchase energy and capacity from eligible renewable resources meeting PG&E's resource needs and California's RPS program for the years 2007 and beyond. Shortlisting of the bids occurred in November 2006, with the execution of final agreements to tentatively occur between Q4 of 2006 and Q1 of 2007. Possible energy and capacity deliveries from the 2006 RPS solicitation are not a part of PG&E's existing resource forecast estimates.

In addition to the monthly energy and capacity forecasts listed above, the annual energy forecast for these contracts are aggregated on line 40 of Tables Vol. 1, IVAX-2 through IVAX-13, and the annual capacity forecast for these contracts are aggregated on line 42 of Tables Vol. 1, IVAX-14 through IVAX-25.

b. Renewable Portfolio Standard Targets and Forecasted Renewable Energy

PG&E intends to procure renewable resources in order to meet its Annual Procurement Target ("APT") of 20% by 2010 consistent with D.06-10-050. However, because the planning horizon of the 2006 LTPP extends through 2016, and because the Scoping Memo requests that the IOUs consider the 33% RPS goal,[32] PG&E is also providing an analysis of a higher renewables target in its 2006 LTPP.[33] There are five components to compliance with the RPS targets used by PG&E in the 2006 LTPP:

- Retail Sales;
- Targets as a percentage of Retail Sales;
- Baseline RPS Procurement;
- Generic forecasted future RPS procurement; and
- Total RPS forecasted deliveries.

Each of these components is discussed below.

(1) Retail Sales

RPS targets are based on a percentage of bundled sales at the meter. In its recently filed 2007 RPS Short Term Plan,[34] PG&E used the 2007 forecast of PG&E's load approved by the CEC in July 2006 for use in the 2007 RA filing, and the high 2005 IEPR load growth. In the 2006 LTPP, PG&E has expanded on its load and retail sales forecast from the 2007 Short Term RPS Plan with the addition of three additional load and retail sales scenarios representing a range of market uncertainty. For a more detailed discussion of the PG&E load forecast and methodology see

[32] Scoping Memo at 20.

[33] Broader policy considerations regarding extending and increasing the RPS goal beyond 20% by 2010 are addressed in Volume 2, Section I.B.5.

[34] 2007 RPS Short Term Plan, R.06-05-027.

Volume 1, Section IV.B.[35] Tables Vol. 1, IVC-7 and IVC-8 show PG&E to have retail sales between approximately 75,000 GWh and 85,000 GWh in 2010.

(2) Targets as a Percentage of Retail Sales

Using the retail sales information described above, PG&E's RPS targets are calculated as follows: in the Basic Procurement Plan and Increased Reliability Plans APT is calculated as 20% of the previous year's retail sales starting in 2010, and in Increased Reliability and Preferred Resources Plan a 25% APT goal in 2016 is calculated as a proxy for going beyond PG&E's existing goals. In the years prior to 2010, APT is calculated as the sum of the previous year's annual procurement plus current year Incremental Procurement Target ("IPT"). Tables Vol. 1, IVC-7 and IVC-8 show PG&E's APT target of between approximately 15,000 GWh and 17,000 GWh in 2010 for the Basic Procurement Plan and Increased Reliability Plans. An APT of 19,000-23,000 GWh is shown in 2016 for the Increased Reliability and Preferred Resources Plan.

(3) Baseline (Including Signed Contracts)

"Baseline" in the 2006 LTPP refers to all signed and operating eligible renewable resources as of October 31, 2006. The four scenarios used in the 2006 LTPP include varying re-contracting rates for these existing contracts, as described above in Volume 1, Section IV.C.2.a. Baseline resources are summarized in Tables Vol. 1, IVC-7 and IVC-8, below. These tables show PG&E to have a baseline of approximately 11,200 GWh to 12,200 GWh in 2010 for all three candidate plans.

(4) Forecasted Future Renewable Energy Procurement

Based on its assessment of resource availability and its RPS experience, PG&E developed a forecast for incremental renewables procurement. This forecast helped PG&E estimate the timing and cost of meeting its RPS targets and provides a frame of reference for determining where and when transmission limitations may arise. There are a number of market uncertainties surrounding PG&E's procurement of incremental renewable resources. These uncertainties impact the amount and timing of renewable energy deliveries and therefore PG&E's ability to meet its RPS targets.

[35] Tables Vol. 1, IVC-7 and IVC-8 below show retail sales forecast over the planning horizon net of projected CEE, DR and DG. For a more detailed discussion of PG&E's CEE, DR, and DG forecasts see Volume 1, Section IV.C.1.

In the 2006 LTPP, PG&E made certain general assumptions about its future RPS procurement. PG&E assumed that it will purchase renewable energy offered by the market, even if it is priced higher than the market price, until the applicable RPS target is met (either 20% or 25%, depending on the plan), producing the lowest cost means to achieve the renewables target. Once PG&E meets its target, PG&E will continue to purchase cost effective renewable resources, as available. The forecast reflected in Tables Vol. 1, IVC-7 and IVC-8 below is a composite of both total renewable market availability up until the RPS target is met, and cost effective renewable resources after the target is met. PG&E also assumed, for planning purposes only, a limit to total purchases of intermittent renewable resources of 10% of bundled sales, until PG&E can assess the impact of these resources on the system.

In the RPS proceeding, PG&E has stated its intent to procure an incremental 1–2% of its load per year (approximately 750-1,500 GWh) until it reaches the 20% RPS goal.[36] PG&E assumed 2% annual incremental RPS procurement in Scenarios 2 and 3 of the 2006 LTPP. PG&E assumed it will procure renewable resources in each of the years of the planning horizon. Scenario 1 reflects declining market availability and decreases the annual availability by 10% per year. Scenario 4 reflects a growing renewables market and increases the annual market availability of renewables by 10%. PG&E assumed that the 2% contracted energy is composed of a resource portfolio similar to what the CEC has forecasted and consistent with what PG&E has seen in its solicitations. PG&E assumed wind will account for approximately 50% of the RPS portfolio, geothermal 15%, biomass 10%, solar 20%, and "other" 5%.[37] However, the ultimate composition is unknown and depends on the commercial response of the market.

While it is difficult to forecast project lead times, PG&E also made some basic assumptions about the timing of deliveries and the resource mix for illustrative purposes. First, PG&E assumed the RPS solicitations are offered at the beginning of

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[36] PG&E's 2007 Solicitation Protocol, R.06-05-027.

[37] The amount of each technology available in the marketplace is highly uncertain. The CEC in its *Renewable Resource Development Report and Strategic Value Analysis*, the Commission in its 33% White Paper, and the Western Governor's Association ("WGA") have all provided estimates of resource availability. The Commission also provided estimates of the portfolio composition of each technology, upon which PG&E based its own estimates. However, PG&E evaluates each offer as part of a Least-Cost Best-Fit process and does not favor one technology over another.

the first calendar year and contracts are signed and approved by the end of the first calendar year. Second, PG&E assumed that wind generation has the shortest development lead time and will start delivering energy two years from the time of the approved contract. This results in deliveries of wind in three years from the date of the issuance of the RFO. PG&E based this assumption on its commercial experience. Third, PG&E assumed the remaining 50% of the portfolio (biomass, geothermal, solar) begins delivering by the end of three years from the time a contract is executed. Some of these projects are scaled up over time and the 3-year lead time reflects an average. There is significant uncertainty regarding lead times. PG&E's renewable energy plan does not explicitly account for this variability and PG&E will update its assumptions as it gains additional commercial experience.

PG&E further discusses the market uncertainty surrounding the renewable energy scenarios in Section IV.C.2.d, below. Tables Vol. 1, IVC-7 and IVC-8 show PG&E to have incremental renewable procurement between 8,500 and 13,000 GWh for the Basic Procurement Plan and the Increased Reliability Plan in 2016 and between 9,000 GWh and 15,000 GWh in 2016 for Increased Reliability and Preferred Resources Plan.

(5) Conclusions

PG&E intends to execute contracts for over 20% of its retail sales in 2010 and meet its 20% RPS target on a delivered basis by 2011-2012. In all scenarios used by PG&E in the 2006 LTPP, PG&E assumed that it executed RPS contracts for over 20% of its retail sales in 2010 and complied with the 20% APT requirements using flexible compliance rules. Under all three proposed plans, under all scenarios, PG&E achieved the 20% RPS target by 2011-2012. However, the plans differ as to the amount above the 20% RPS target that is achieved after 2012. These differences are identified in Tables Vol. 1, IVC-7 and IVC-8.

c. PG&E Planned Renewable Resources

(1) Wind

The CEC has identified significant technical potential for wind development to meet PG&E's RPS goals. Resource areas with significant promise include: the Tehachapi and San Bernardino resource areas in southern California; the Lassen, Siskiyou, and Solano resource areas in northern California; and Oregon, Washington, and Nevada imports. PG&E is also investigating resource potential in British

Columbia, but did not include that region in the forecasts pending additional research to validate resource potential. PG&E currently has contracts for the purchase of wind energy from a number of wind projects in its service territory including the Altamont and Solano resource areas. Because wind is the lowest cost renewable resource, PG&E expects that wind energy will continue to play a significant role in its RPS portfolio. The CEC and CPUC have projected[38] as much as 50% of California's RPS needs will be met with wind energy, and in this plan PG&E anticipates similar levels. PG&E provided additional detail on resource potential in its 2006 RPS Short Term Plan[39] and December 2005 Supplement to its RPS Long Term Plan.[40]

In addition to the contracts for [redacted] MW of wind generation, which PG&E has entered into since the beginning of the RPS program, PG&E's Scenario 2 in the Increased Reliability and Preferred Resources Plan assumes an additional 1,300 MW of SP26 Wind, 700 MW of NP26 Wind, and 400 MW of imports from the Northwest and Nevada over the planning horizon. However, since most of these resource areas require significant transmission additions, as described in more detail in Volume 1, Section V.H.4, there is significant uncertainty regarding the availability of transmission capacity and consequent effect on wind resource deliveries.

Studies are under way at the CEC to determine the system's ability to manage increasing wind penetration levels.[41] While many questions remain to be addressed, PG&E has estimated the additional peaking capacity needed to close the gap between the Commission-adopted counting rules, and the actual output of wind at the time of CAISO's peak hours. PG&E's analysis is summarized in Volume 1, Section IV.H.

(2) Geothermal

The CEC and the WGA have identified significant geothermal resource areas both inside and outside of California. PG&E has previously commented on these areas in its 2006 Short Term Plan[42] and December 2005 Supplement to its RPS

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[38] CPUC, Achieving a 33% Renewable Energy Target, November 2005.

[39] R.06-05-027, PG&E Renewable Energy Procurement Plan.

[40] R.04-04-026, Supplement to PG&E's 2005 Renewable Energy Procurement Plan.

[41] California Energy Commission Public Interest Energy Research ("PIER") Program's Intermittency Analysis Project: 2006 Renewable Baseline and 2010 RPS Scenario Results.

[42] R.06-05-027, PG&E Renewable Energy Procurement.

Long-Term Plan.[43] Geothermal energy has the benefit of being a baseload resource which would deliver reliable capacity and energy to PG&E. In addition to the 450 MW of geothermal contracts which PG&E has entered since the beginning of the RPS program, under Scenario 2 in PG&E's Increased Reliability and Preferred Resources Plan, PG&E assumes an additional 200 MW of Geothermal resources from the Salton Sea, northeastern California, and Import resource areas. However, since most of these resource areas require significant transmission additions described in more detail in Volume 1, Section V.H.4, there is significant uncertainty regarding the availability of transmission capacity and consequent effect on geothermal resource deliveries.

(3) Solar

The CEC identifies solar as the most abundant and untapped renewable energy resource in California. Solar production (especially where tracking is used) correlates reasonably well with PG&E's peak demand, and despite its cost, solar could provide relatively high value energy to PG&E. While the most optimal locations for Concentrating Solar Thermal ("CSP") are south of PG&E's service territory, it is less problematic to access than other renewable resources because the congestion on North of Path-15 ("NP15") from the south to north occurs during off-peak hours.[44] Although solar is still relatively expensive, PG&E believes there could be incremental cost reductions over the planning horizon.

(4) Biomass

The CEC, Commission, and the Governor have identified the value of biomass in California. PG&E has signed [redacted] MW of bioenergy contracts since the beginning of the RPS program. However, these additions are all repowered facilities. While PG&E believes a new biomass plant is less cost effective than wind, PG&E also recognizes that biomass provides unique benefits to Californian and PG&E customers. Accordingly, PG&E is working closely with the dairy industry and biomass producers and regulators such as the San Joaquin Valley Air Pollution Control District to support the development of biomass and biogas projects. PG&E provides more detail about its biopower activities in Volume 1, Section V.D.

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[43] R.04-04-026, Supplement to PG&E's 2005 Renewable Energy Procurement Plan.

[44] While the 2006 LTPP does not explicitly address the Carizzo plains resource area, PG&E believes it is another promising solar resource area.

(5) Emerging Technologies

The CEC, the Electric Power Research Institute ("EPRI"), and the Commission have identified a number of emerging renewable resources. PG&E is interested in, and in many cases actively pursuing, emerging technologies such as wave, tidal, biogas to biomethane, solar, solar PV, and others. Development of these resources is highly uncertain because the technology is often expensive and risky and projects face significant barriers. However, PG&E is proposing an Emerging Renewable Resource Program in this plan in Volume 2, Section I.B.5, which it hopes will help demonstrate pre-commercial technology and new renewable resources.

(6) Repowering

For renewables, repowering mainly applies to existing wind projects. Many of PG&E's existing wind projects are located in the Altamont Pass in Alameda County, California. The Alameda County Board of Supervisors recently adopted conditions for the continued use of land for wind generation in the Altamont area. These conditions sometimes require additional review and permitting for proposed repowering projects, including reconfiguration and relocation of wind generating units that have been found to endanger birds.

Developers have indicated that repowering has the potential to increase the productivity of particular wind turbines. However, repowering requires a substantial capital investment and compliance with as yet unknown permit constraints. Without knowing the operating parameters, developers, investors, and lenders are understandably reluctant to make such investments. Thus, it is unlikely that a significant portion of the existing wind projects in the Altamont area will be repowered until final permit conditions are issued by the county. Nonetheless, PG&E intends to proactively seek out wind developers to determine if renegotiation of existing power purchase agreements would enable repowering.

(7) British Columbia Renewables

Renewable resources in British Columbia ("BC") represent a potential supply source to PG&E that could be instrumental in achieving higher penetrations of renewables. A recent study by BC Hydro identified more than 21,000 GWh per year of developable resources, with estimated production costs of less than U.S. $0.08 per kWh (based on current exchange rates).

These out-of-state renewable resources would enhance PG&E's energy reliability, along with adding geographic and resource diversity to PG&E's renewable portfolio. BC's developable renewable resources are estimated to consist of the following:

- Wind (5,200 MW of potential capacity);
- Small and medium hydro resources (4,300 MW of capacity);
- Biomass (157 MW of capacity); and
- Geothermal (200 MW of capacity).

An additional benefit associated with BC renewable resources is the strong complementary relationship between the seasonal demands of summer-peaking California and winter-peaking BC that allows for the sharing of resources in order to beneficially meet the needs of both jurisdictions. On August 9, 2006, PG&E filed an application with the Commission requesting recovery of up to $14 million in external costs required to assess the feasibility of obtaining renewable electric power from BC, and transmitting that power into PG&E's service territory.[45] PG&E's application is still pending before the Commission.

(8) Other Renewable Resource Areas

PG&E recognizes the availability of renewable resources in promising resource areas in California. PG&E completed a Geographic Information System ("GIS") project that mapped Renewable Resources in California. This work builds on the previous work of the CEC and the Commission and identifies high priority renewable resource areas. The results of that study will be used in prioritizing future emerging resource support. Studies of renewable resources in other states in the west were also reviewed, but not included in projections pending a better understanding of the transmission required to deliver those resources to California.

d. Context of the Plan

PG&E's plan for long-term procurement of specific types and quantities of renewable resources illustrates how PG&E might achieve its RPS goals. However, PG&E's plans assume that adequate resources and transmission exist or will be

[45] *See* A.06-08-011.

developed, and that certain types of resources will respond to utility solicitations at certain periods. The commercial response, not a prescribed plan, will ultimately determine what resources are developed and when they are developed.

As stated above, PG&E has developed four scenarios to, among other purposes, represent the range of uncertainty of the market availability of renewable energy across the planning horizon. Scenario 1 represents a declining market where the best renewable projects have been developed and other RPS markets are attractive. Scenarios 2 and 3 are scenarios where the availability of renewables in the marketplace is consistent throughout the planning horizon. Scenario 4 reflects a situation where a significant number of new renewable resources are available in the marketplace year to year. In general, the range of uncertainty reflects:

- Readiness of resource (permitting, resource confirmation);
- External Market Attractiveness (interest in California relative to other markets);
- IOU competition for resources;
- Learning, Scale, Technology Breakthroughs; and
- Industry Health/Power (Sellers market).

TABLE VOL. 1, IVC-6
PACIFIC GAS AND ELECTRIC COMPANY
RENEWABLE ENERGY AND PLANNING SCENARIOS

Line No.	Component Baseline	Scenario 1 High Attrition	Scenario 2 Medium Attrition	Scenario 3 Medium Attrition	Scenario 4 Low Attrition
1	Incremental	Declining Market Availability	Stable Market Availability (approximately 1500 GWh)	Stable Market Availability; Declining Renewables Prices	Growing Market Availability

TABLE VOL. 1, IVC-7
PACIFIC GAS AND ELECTRIC COMPANY
PG&E TOTAL RENEWABLE ENERGY PLAN BASIC PROCUREMENT PLAN
AND INCREASED RELIABILITY PLAN
(GWH UNLESS SPECIFIED OTHERWISE)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Scenario 1 – Stranded Cost										
2	Retail Sales	[redacted]	[redacted]	[redacted]	74,708	73,821	72,921	73,930	74,937	75,968	77,074
3	APT	[redacted]	[redacted]	[redacted]	14,942	14,764	14,584	14,786	14,987	15,194	15,415
4	Baseline	10,487	10,981	11,219	11,221	11,364	11,376	9,496	8,928	8,337	7,948
5	RPS Forecast	–	750	1,500	2,925	4,208	5,362	6,401	7,336	8,177	8,593
6	Total RPS Energy	10,487	11,731	12,719	14,146	15,571	16,738	15,897	16,264	16,514	16,541
7	RPS % of sales	[redacted]	[redacted]	[redacted]	18.9%	21.1%	23.0%	21.5%	21.7%	21.7%	21.5%
8	APT %	13.3%	14.6%	15.8%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
9	Scenario 2 — Current World - Lower Preferred Resources										
10	Retail Sales	[redacted]	[redacted]	[redacted]	80,582	81,730	82,907	84,145	85,407	86,710	88,099
11	APT	[redacted]	[redacted]	[redacted]	16,116	16,346	16,581	16,829	17,081	17,342	17,620
12	Baseline	10,492	11,026	11,560	11,831	11,994	12,008	11,070	10,850	10,624	10,485
13	RPS Forecast	–	750	1,500	3,000	4,500	6,000	7,500	8,288	8,325	8,363
14	Total RPS Energy	10,492	11,776	13,060	14,831	16,494	18,008	18,570	19,138	18,949	18,848
15	RPS % of sales	[redacted]	[redacted]	[redacted]	18.4%	20.2%	21.7%	22.1%	22.4%	21.9%	21.4%
16	APT %	13.3%	14.2%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
17	Scenario 3 — Current World - Adequate Preferred Resources										
18	Retail Sales	[redacted]	[redacted]	[redacted]	80,525	81,637	82,777	83,974	85,194	86,451	87,791
19	APT	[redacted]	[redacted]	[redacted]	16,105	16,327	16,555	16,795	17,039	17,290	17,558
20	Baseline	10,492	11,026	11,560	11,831	11,994	12,008	11,070	10,850	10,624	10,485
21	RPS Forecast	–	750	1,500	3,000	4,500	6,000	7,500	9,000	10,125	11,250
22	Total RPS Energy	10,492	11,776	13,060	14,831	16,494	18,008	18,570	19,850	20,749	21,735
23	RPS % of sales	[redacted]	[redacted]	[redacted]	18.4%	20.2%	21.8%	22.1%	23.3%	24.0%	24.8%
24	APT %	13.3%	14.2%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
25	Scenario 4 — High Price, High Growth										
26	Retail Sales	[redacted]	[redacted]	[redacted]	84,944	87,302	89,544	90,455	91,322	92,185	93,011
27	APT	[redacted]	[redacted]	[redacted]	16,989	17,460	17,909	18,091	18,264	18,437	18,602
28	Baseline	10,498	11,055	11,796	12,273	12,449	12,466	12,444	12,445	12,447	12,464
29	RPS Forecast	–	750	1,500	3,075	4,808	6,713	8,810	10,017	11,346	12,808
30	Total RPS Energy	10,498	11,805	13,296	15,348	17,256	19,179	21,253	22,463	23,793	25,272
31	RPS % of sales	[redacted]	[redacted]	[redacted]	18.1%	19.8%	21.4%	23.5%	24.6%	25.8%	27.2%
32	APT %	13.3%	13.9%	14.5%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%

TABLE VOL. 1, IVC-8
PACIFIC GAS AND ELECTRIC COMPANY
PG&E TOTAL RENEWABLE ENERGY FOR INCREASED RELIABILITY AND PREFERRED RESOURCES PLAN
(GWH UNLESS SPECIFIED OTHERWISE)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Scenario 1 – Stranded Cost										
2	Retail Sales	[redacted]	[redacted]	[redacted]	74,708	73,821	72,921	73,930	74,937	75,968	77,074
3	APT	[redacted]	[redacted]	[redacted]	14,942	14,764	14,584	14,786	14,987	15,194	19,269
4	Baseline	10,487	10,981	11,219	11,221	11,364	11,376	9,496	8,928	8,337	7,948
5	RPS Forecast	–	750	1,500	2,925	4,208	5,362	6,401	7,336	8,177	8,934
6	Total RPS Energy	10,487	11,731	12,719	14,146	15,571	16,738	15,897	16,264	16,514	16,882
7	RPS % of sales	[redacted]	[redacted]	[redacted]	18.9%	21.1%	23.0%	21.5%	21.7%	21.7%	21.9%
8	APT %	13.3%	14.6%	15.8%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	25.0%
9	Scenario 2 — Current World - Lower Preferred Resources										
10	Retail Sales	[redacted]	[redacted]	[redacted]	80,582	81,730	82,907	84,145	85,407	86,710	88,099
11	APT	[redacted]	[redacted]	[redacted]	16,116	16,346	16,581	16,829	17,081	17,342	22,025
12	Baseline	10,492	11,026	11,560	11,831	11,994	12,008	11,070	10,850	10,624	10,485
13	RPS Forecast	–	750	1,500	3,000	4,500	6,000	7,500	9,000	10,500	12,000
14	Total RPS Energy	10,492	11,776	13,060	14,831	16,494	18,008	18,570	19,850	21,124	22,485
15	RPS % of sales	[redacted]	[redacted]	[redacted]	18.4%	20.2%	21.7%	22.1%	23.2%	24.4%	25.5%
16	APT %	13.3%	14.2%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	25.0%
17	Scenario 3 — Current World - Adequate Preferred Resources										
18	Retail Sales	[redacted]	[redacted]	[redacted]	80,525	81,637	82,777	83,974	85,194	86,451	87,791
19	APT	[redacted]	[redacted]	[redacted]	16,105	16,327	16,555	16,795	17,039	17,290	21,948
20	Baseline	10,492	11,026	11,560	11,831	11,994	12,008	11,070	10,850	10,624	10,485
21	RPS Forecast	–	750	1,500	3,000	4,500	6,000	7,500	9,000	10,500	12,000
22	Total RPS Energy	10,492	11,776	13,060	14,831	16,494	18,008	18,570	19,850	21,124	22,485
23	RPS % of sales	[redacted]	[redacted]	[redacted]	18.4%	20.2%	21.8%	22.1%	23.3%	24.4%	25.6%
24	APT %	13.3%	14.2%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	25.0%
25	Scenario 4 — High Price, High Growth										
26	Retail Sales	[redacted]	[redacted]	[redacted]	84,944	87,302	89,544	90,455	91,322	92,185	93,011
27	APT	[redacted]	[redacted]	[redacted]	16,989	17,460	17,909	18,091	18,264	18,437	23,253
28	Baseline	10,498	11,055	11,796	12,273	12,449	12,466	12,444	12,445	12,447	12,464
29	RPS Forecast	–	750	1,500	3,075	4,808	6,713	8,810	11,116	13,652	15,114
30	Total RPS Energy	10,498	11,805	13,296	15,348	17,256	19,179	21,253	23,561	26,099	27,578
31	RPS % of sales	[redacted]	[redacted]	[redacted]	18.1%	19.8%	21.4%	23.5%	25.8%	28.3%	29.7%
32	APT %	13.3%	13.9%	14.5%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	25.0%

3. Existing and Committed Supply-Side Resources

In addition to the demand-side and renewable resources discussed above, PG&E's procurement plans include other supply-side resources. PG&E is providing the following information reflecting the various scenarios and candidate plans:[46]

- Table Vol. 1, IVAX-1 includes a list of each supply-side resource and its corresponding capacity, availability, locational attribute, delivery point, fuel type and contract type. The last column indicates the line item to which the resource is mapped in the monthly capacity tables;
- Tables Vol. 1, IVAX-2 through IVAX-13 are the annual energy balance tables for the four scenarios and the three candidate procurement plans. The line numbering convention corresponds directly to the line numbers in the less aggregated monthly tables;
- Tables Vol. 1, IVAX-14 through IVAX-25 are the annual capacity balance tables for the four scenarios and the three candidate procurement plans. The line numbering convention corresponds directly to the line numbers in the less aggregated monthly tables;
- Tables Vol. 1, IVAX-26 through IVAX-37 are the monthly energy balance tables for the four scenarios and the three candidate procurement plans;
- Tables Vol. 1, IVAX-38 through IVAX-49 are the monthly capacity balance tables for the four scenarios and the three candidate procurement plans; and
- Table Vol. 1, IVAX-50 is an explanation of differences between the above listed tables and the CEC's Forms and Instructions for Submitting Electricity Resource Plans Prepared in Support of the 2007 Integrated Energy Policy Report (IEPR), Staff Draft, dated November 9, 2006.[47]

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[46] Volume 1, Section IV.A.1 discusses scenarios and Volume 1, Section IV.H discusses candidate plans.

[47] On November 13, 2006 parties from the Commission, CEC, PG&E, SCE, and SDG&E conferred via phone and agreed to use the format of the CEC's proposed IEPR monthly energy and capacity forms to the extent possible, and to explain any differences between the CEC's instructions and the monthly energy and capacity tables presented in the IOU's LTPPs. The CEC's original November 9, 2006 draft forms and instructions are located in Attachment IVA of Volume 1.

The remainder of this section describes the existing and committed supply-side resources considered in PG&E's planning process. New or proposed demand- and supply-side resources are also included in the above referenced tables.

a. Utility Retained Generation

Utility Retained Generation ("URG") resources include PG&E's existing hydroelectric, nuclear, and fossil resources, less any retirements and contract terminations.

PG&E's hydroelectric system consists of 69 powerhouses, which are licensed by the Federal Energy Regulatory Commission ("FERC"). In preparing the 2006 LTPP resource forecast, PG&E assumed that all hydroelectric licenses expiring during the forecast period would be renewed by FERC, and that renewed license conditions would not impair the capacity or energy deliveries of the projects. The forecasted amounts of energy available from PG&E's retained hydroelectric plants are based on a normal hydro year.

In addition to these hydroelectric resources, PG&E also has existing hydro-partnership contracts with a number of irrigation districts and water agencies. As with PG&E's owned hydroelectric facilities, the forecasted amounts of energy available from these contracts are based on a normal hydro year. In preparing the 2006 LTPP, PG&E assumed that a portion of these contracts will be renewed.[48] The portion of these contracts which are assumed to expire will add to the amounts of purchased power that PG&E will need to procure. However, the power associated with these projects would remain available in the California market. The monthly energy forecast is shown on lines 14-15 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 16-18 of Tables Vol. 1, IVAX-38 through IVAX-49.

PG&E also owns and operates twin nuclear power units at Diablo Canyon. PG&E replaced the low-pressure turbine rotors for Unit 1 after its October 2005 refueling outage and initial tests indicated increased output. After its April 2006 refueling outage and low-pressure turbine rotor replacement, Unit 2 is also estimated

[48] Volume 1, Section IV.C.3.g, describes the expiration assumptions.

to have similar increased output.[49] The plant is expected to have an availability of over 95 percent annually, excluding refueling outages. The monthly energy forecast is shown on line 10 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on line 12 of Tables Vol. 1, IVAX-38 through IVAX-49.

PG&E's existing fossil generation forecast for the planning horizon includes only the Humboldt Bay Power Plant ("HBPP"), located three miles south of Eureka.[50] HBPP operates two natural gas-fired boilers as well as two combustion turbines that operate on distillate fuel. HBPP is required to operate for local system reliability. The monthly energy forecast is shown on line 11 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on line 13 of Tables Vol. 1, IVAX-38 through IVAX-49. As part of PG&E's 2004 LTRFO, various bids were evaluated to provide replacement generation which would allow PG&E to retire the HBPP facility. The successful 2004 LTRFO offer will result in a new facility that will be owned by PG&E that is scheduled to be by 2009. The existing HBPP facility is assumed to be retired at that point. Additional discussion on the new HBPP facility is provided in the next section.

b. Expected Utility-Owned Resources

In April 2006, PG&E submitted its 2004 LTRFO application to the Commission which provides for 820 MW of capacity through two facilities to be owned by PG&E. PG&E has entered into a Purchase and Sale Agreement ("PSA") with E&L Westcoast, LLC which will design, develop, construct and commission (according to PG&E's specifications) the E&L Westcoast Colusa Project, located in the Central Valley, north of Sacramento. E&L Westcoast Colusa is an efficient combined-cycle power plant that will have duct-firing capability to provide peaking power. The facility is ideally located beside PG&E's natural gas transmission pipelines as well as PG&E's 230 kV transmission lines. The operation date for this facility is expected to occur in mid-2010. The facility will continue to operate well past the 2016 planning horizon of this forecast. The monthly energy forecast is

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[49] In addition, PG&E anticipates replacing the steam generators for the two units during their respective refueling outage in 2008 and 2009. No increase in capacity arises from the replacement of steam generators but longer refueling outages are required to implement the replacement.

[50] PG&E's Hunters Point Units 1 and 4 are no longer included as they were retired in May 2006 with the completion of several key transmission projects, including the Jefferson-Martin 230 kilovolt ("kV") transmission line.

shown on line 12.a of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on line 14.a of Tables Vol. 1, IVAX-38 through IVAX-49.

The 2004 LTRFO also included a solicitation to provide power to the HBPP load pocket. As a result of the LTRFO solicitation, PG&E entered into an Engineering, Procurement and Construction ("EPC") contract with Wartsila North America, Inc. to construct a reciprocating engine generation facility, located adjacent to the existing HBPP facility. The operation date for this facility is expected to occur in mid-2009. The monthly energy forecast is shown on line 12 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on line 14 of Tables Vol. 1, IVAX-38 through IVAX-49.

The transfer of the Gateway Generating Station ("Gateway")[51] from Mirant to PG&E is one element of a larger settlement agreement with Mirant, announced in January 2005, that resolved alleged market manipulation claims and overcharges from the sale of electricity by Mirant's California operations during the energy crisis. Gateway is a partially constructed combined-cycle generation facility located near Antioch, California. Gateway will also have duct-firing capabilities. Gateway's Bay Area location will provide local reliability benefits as well as enhance the reliability of the state's energy supply. This facility is forecasted to become operational by mid-2009. The monthly energy forecast is shown on line 12.b of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on line 14.b of Tables Vol. 1, IVAX-38 through IVAX-49.

c. Qualifying Facilities

PG&E has PPAs with approximately 260 QFs. PG&E developed its QF forecast using project-specific generation from each QF larger than 1 MW in size. For QFs smaller than 1 MW, PG&E uses aggregated historical generation by technology as a basis for its forecast. In total, QFs smaller than 1 MW comprise only about 1% of total QF energy deliveries. Only QFs currently in operation, including those who received Standard Offer 1 ("SO1") contract extensions as indicated below, were included in the forecast. QFs with terminated or bought-out contracts were excluded from the forecast, as were those QFs which have failed to operate for more than a year.

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[51] Contra Costa 8 was recently renamed the Gateway Generating Station.

Aside from variability in annual hydro and wind conditions and the market anomalies that occurred during 2000 and 2001, PG&E has seen fairly consistent production from QFs from year to year. Forecast generation for fossil, thermal renewable, and wind QFs are generally based on actual generation from 2003-2005. PG&E excluded the last four months of 2005 for certain thermal generation projects which uncharacteristically decreased or shut down operations entirely due to unusual market conditions as a result of Hurricanes Katrina and Rita. For hydro QFs, PG&E bases its annual projections on historical production from 1991-2005, adjusted to average water year conditions. For certain QFs that have recently returned to operation, PG&E uses the most recent 12 to 24 months of PPA generation. Finally, the generation for a QF with contractual dispatch features was estimated using an economic dispatch model.

In preparing its 10-year forecast of resources, PG&E has assumed that a portion of these PPAs will be renewed. The monthly energy forecast is shown on lines 28-35 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 30-37 of Tables Vol. 1, IVAX-38 through IVAX-49.

d. California Department of Water Resources Contracts

In D.02-09-053, the Commission allocated the power available from all DWR contracts with a specified delivery point at NP15, plus the Coral contract, to PG&E. By 2012 (when the majority of these contracts expire), PG&E forecasts energy deliveries from these contracts to reduced, which reflects decreased deliveries due to contract termination assumptions. The monthly energy forecast is shown on lines 24 – 27 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 26-29 of Tables Vol. 1, IVAX-38 through IVAX-49. In Volume 2, Section I.B.4, PG&E discusses the implications of expiring DWR contracts for procurement practices.

e. Other Existing Bilateral Contracts

In addition to the contracts described above, PG&E has a number of other bilateral contracts for existing supply-side resources that were in place during the preparation of the LTPP analysis:

- Under the Puget Sound Power and Light ("PSPL") contract, PG&E receives capacity and energy from between June and September. PG&E is obligated to return similar amounts of capacity and energy to PSPL between November and February. The amount of energy exchanged under this contract is 413 GWh. This contract is an evergreen contract with a 5-year termination notice. The monthly energy forecast is shown on lines 8 and 41 of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 10 and 43 of Tables Vol. 1, IVAX-38 through IVAX-49.

- As part of Mirant's bankruptcy claim settlement, PG&E has executed agreements with Mirant which provide PG&E the right to dispatch power from certain northern California units owned by Mirant.[52] Additionally, PG&E will receive capacity credit from these resources for purposes of meeting its RA requirements. The monthly energy forecast is shown on lines 42-43g of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 44-45g of Tables Vol. 1, IVAX-38 through IVAX-49.

- In April 2005, the Commission approved a 3-year physical tolling arrangement between PG&E and Duke Energy Marketing Americas' Morro Bay Units 3 and 4 (Resolution E-3929). The monthly energy forecast is shown on lines 43h and 43i of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 45h and 45i of Tables Vol. 1, IVAX-38 through IVAX-49.

- On March 2, 2006, PG&E entered into a physical tolling arrangement with Duke Energy Marketing Americas' Moss Landing Units 6 and 7 for RA and energy deliveries from May 1, 2006 through December 31, 2006.[53] For purposes of this forecast, PG&E projects RA and energy deliveries will be available to PG&E during 2010. The monthly energy forecast is shown on lines 43j and 43k of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 45j and 45k of Tables Vol. 1, IVAX-38 through IVAX-49.

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[52] Approvals from the Commission, FERC, and Mirant's Bankruptcy Court were granted on January 13, April 13-14, 2005, respectively.

[53] PG&E filed Advice Letter 2803-E on March 24, 2006, which requested Commission review and approval to extend the agreement from 2007 through 2010.

- PG&E conducted a competitive solicitation (known as RFO 8) for shapeable energy products from 2006 through 2008. PG&E received multiple offers and signed three contracts on May 5, 2005. The monthly energy forecast is shown on lines 43l – 45o of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 45l – 45o of Tables Vol. 1, IVAX-38 through IVAX-49.

- In response to Western Area Power Administration's Request for Offers ("RFO") for RA capacity for 2007, PG&E entered into a contract to sell RA capacity for the January through April and October through December 2007 time period. The monthly energy forecast is shown on line 43p Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on line 45p of Tables Vol. 1, IVAX-38 through IVAX-49.

- In response to PG&E's July 2006 solicitation for 2007 RA capacity products for Bay Area local capacity needs, PG&E entered into contracts with Calpine Energy Services to fulfill much of PG&E's 2007 local capacity requirements from their Los Medanos and Metcalf facilities. Pending Commission approval, these contracts will be extended through 2011. PG&E assumes these contracts will be approved. The monthly energy forecast is shown on lines 43q and 43r of Tables Vol. 1, IVAX-26 through IVAX-37. The monthly capacity forecast is shown on lines 45q and 45r of Tables Vol. 1, IVAX-38 through IVAX-49.

f. 2004 Long-Term Request for Offers – Purchase Power Agreements

In April 2006, PG&E submitted its 2004 LTRFO application to the Commission requesting approval of five PPAs which are comprised of new additions to the northern California power market. The PPAs include combined cycle technology, simple cycle combustion turbines and reciprocating engine. The location of approximately 50% of the PPA capacity is in the transmission constrained San Francisco Bay Area. The contract terms range from 10 to 20 years in length, and are forecasted to be operational between mid-2009 and mid-2010. The monthly energy forecast is shown on lines 43w and 43w of Tables Vol. 1, IVAX-26 through

IVAX-37. The monthly capacity forecast is shown on lines 45s and 45w of Tables Vol. 1, IVAX-38 through IVAX-49.

g. Contract Renegotiation Assumptions

As described above, PG&E has PPAs with numerous entities. In preparing the 2006 LTPP, PG&E forecasted that some contracts will be renegotiated and others will expire. PG&E assumed various recontracting rates in developing its portfolio planning scenarios, the majority of generation under expiring QFs, renewable and Irrigation District (“ID”) and Water Agency contracts are not expected to retire and the power associated with these projects would remain available in the California market. PG&E’s portfolio contract renewal assumptions are listed below:

TABLE VOL. 1, IVC-9
PACIFIC GAS AND ELECTRIC COMPANY
PG&E’S PORTFOLIO CONTRACT RENEWAL ASSUMPTIONS

Line No.		Scenario 1 Stranded Cost	Scenario 2 Current World Low Preferred Resources Availability	Scenario 3 Current World Adequate Preferred Resources Availability	Scenario 4 High Price, High Growth
1	RPS QF Recontracting	33%	75%	75%	100%
2	IDWA Recontracting	50%	80%	80%	100%
3	Existing Bilateral RPS Contracts	0%	50%	50%	100%

In addition to the RPS QF recontracting assumptions outlined above, 90% of non-RPS QF PPAs are assumed to be renewed in all scenarios.

D. Planning Scenarios

In this section, PG&E introduces the uncertainties that impact its procurement planning. These uncertainties were used to develop the scenarios that PG&E used to test candidate procurement plans. This section starts with a description of procurement uncertainties divided in three categories: short-term cyclical uncertainties, long-term structural uncertainties, and commercial uncertainties. Then, PG&E explains how it developed four scenarios from these uncertainties. The scenarios are designed to test PG&E’s candidate plans under moderate and high stress conditions.

1. Uncertainties

a. Short-Term Cyclical Uncertainties

There are a number of short-term cyclical uncertainties that must be considered in the planning process.

(1) Weather Impact on Peak Demand

Short-term weather fluctuations affect customer demand for electricity. For planning purposes, the Commission has adopted the use of a 1-in-2 temperature expected (or mean) peak demand, and requires LSEs to provide 15-17% planning reserves to cover this and other similar short-term risks. However, weather can increase peak demand above the expected 1-in-2 peak demand forecasted. The CEC estimates that a 1-in-10 year hot weather event could increase peak demand by approximately 700 MW in northern California above the 1-in-2 temperature expected peak demand.[54] That is, a hot weather event with a 10% chance of occurring can increase the expected 1-in-2 customer peak demand by 700 MW. To the extent Load-Serving Entities ("LSE") carry planning reserves, the area will be able to meet hotter than 1-in-2 temperature peaks; however, as shown in Volume 2, Section I.B.2, the current 15-17% Planning Reserve Margins ("PRM") are not enough to cover a 1-in-10 temperature expected peak.

(2) Hydro Generation

Weather affects PG&E's hydro generation and the availability of surplus energy from the Pacific Northwest, both of which have an impact on the availability and price of electricity. For planning purposes, the Commission has adopted the use of a 1-in-5 adverse weather year to estimate the qualifying RA capacity of PG&E's hydro resources.

(3) Resource Outages

Uncertainties also arise from forced outages. Western Electricity Coordinating Council's ("WECC") Minimum Operating Reliability Criteria ("MORC") provides for operating reserves to cover the largest contingency. On a planning basis, the WECC's Power Supply Design Criteria recommends the monthly generation capacity, after subtracting planned outages, exceed at a minimum of the largest risk

[54] CEC's June 30, 2006 Revised Summer 2006 Demand and Five Year Outlook, posted July 5, 2006.

plus 5% of load or the two largest contingencies, whichever is greater.[55] The CEC Outlook assumes 1,100 MW of planned and forced outages based on historical levels. Forced outages may exceed average levels. For example, to test NP26's resource adequacy, the CEC adds 500 MW of additional forced outages for adverse conditions (one standard deviation from the historical average level for northern California).

(4) Market Price Volatility

Price volatility impacts PG&E's customer costs. The resulting cost impact depends on the open position of PG&E's portfolio, and the corresponding forward market prices and price volatilities. The forward market prices for natural gas and electricity, and their respective price volatilities, which PG&E uses in its scenarios are described in Volume 1, Section III.A.8, and included in Section IV.F.

b. Long-Term Structural Uncertainties

Long-term structural uncertainties can impact the entire region (*i.e.*, NP26) or PG&E's portfolio only. In this section, PG&E describes these uncertainties and their respective impacts on PG&E's portfolio. Table Vol. 1, IVD-1, at the end of this section, summarizes the values or states of these uncertainties used for the four scenarios that PG&E used to evaluate its candidate procurement plans.

(1) Long-Term Load Growth

Volume 1, Section IV.B describes the uncertainty range associated with long-term load growth. The load assumptions used for PG&E's four scenarios are summarized in Table Vol. 1, IVB-1.

(2) Structural Changes in Market Prices

The uncertainty associated with structural changes in market prices impacts PG&E's generation costs. Structural changes are due to changes in technology, regulation, or environmental factors affecting the cost of electricity and natural gas. To capture this uncertainty in the evaluation of its procurement plans, PG&E ran thousands of natural gas and electricity price scenarios in a Monte Carlo simulation. From those scenarios PG&E selected high and low price sensitivities. The current forward prices and the high and low sensitivities are included in Volume 1, Section IV.F.

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[55] WECC 2005 Power Supply Assessment, May 31, 2005, p. 5.

(3) Market Availability of Customer Energy Efficiency, Demand Response, Renewables and Distributed Generation

The market availability of California's preferred resources affects the type and amount of residual resources needed to meet PG&E's bundled customer needs. Volume 1, Sections IV.C. 1 and IV.C. 2, explain the uncertainty associated with the market availability of CEE and DR, DG and renewable generation. PG&E used several approaches to estimate the amounts of preferred resources that will likely be available in the market. The approaches PG&E used to estimate the range of market availability and cost of preferred resources are presented in the sections referenced above.

(4) Existing Fossil Retirements

The CEC proposes that the IOUs' planning and procurement activities accommodate its recommended replacement of certain aging power plants by 2012. To accomplish the retirement of all these plants by 2012, the CEC uses a 4-year ramp-up, from 2009-2012, of incremental procurement of new resources. Volume 1, Section IV.E.1 describes the retirement assumptions used for the scenarios. Two of PG&E's scenarios assume that all aging power plants retire as proposed by the CEC by 2012. The other two scenarios assume a slower retirement schedule.

(5) Resource Adequacy Qualifying Capacity Uncertainty

In D.05-10-042, the Commission adopted counting rules for loads and resources for purposes of demonstrating resource adequacy. These rules are likely to evolve over time.[56] PG&E understands the Commission, together with CAISO and CEC, plan to review how resources performed during high heat days since the inception of the RA program and may propose changes to the counting rules.

[56] For example, with regards to DR, D.05-10-042 acknowledged the CAISO's concern that only four days per month is potentially insufficient for RA, and concurred with the CAISO's recommendation further discuss this issue in future Resource Adequacy Requirement ("RAR") proceedings. Also, although D.05-10-042 rejected CAISO's recommendation that emergency-only DR resources should not count for RA requirements, this issue could be reconsidered in future phases of the RA proceeding. Similarly, with respect to the qualifying capacity of solar and wind, D.05-10-042 acknowledged the CAISO's observation that wind and solar production can vary dramatically across the afternoon hours, and that the adopted six-hour window of SO1 hours used to measure these resources RA capacity exaggerates their RA value.

Furthermore, the CAISO has proposed performance monitoring metrics, which if adopted would reduce the RA qualifying capacity of resources with higher than average forced outage rates. PG&E expects these and other issues will continue to be discussed over time, and could reduce the RA capacity value that PG&E currently counts for these resources, with the resulting increase in its resource procurement needs.

In D.06-06-064, the Commission adopted Local RA requirements for 2007. Additional zonal requirements will be taken up in the next phase of RA. It is difficult to determine how much these requirements will affect PG&E since no proposal has explicitly stated what the requirement will be, but it is likely to exert additional upward pressure on the RA requirement level. Estimates of the potential impact of changes in RA counting rules are difficult to make. However, for the immediate purpose of estimating the uncertainty in RA counting rules, and the associated increase in procurement needs, PG&E assumes the RA counting rules will increase its procurement needs by 500 MW in the planning horizon.

(6) Direct Access Customers Return or Departure and Potential Community Choice Aggregation Departure

DA customers' migration back to bundled service increases PG&E's procurement needs. Currently, the direct access option is suspended. Recent trends show direct access load continues to decrease, migrating to bundled service.

In contrast to direct access migration, several entities have expressed desire to take advantage of the CCA to receive commodity service outside of the utility bundled service. Although no party has yet taken advantage of this option,[57] if and when it happens, CCA will reduce PG&E's procurement needs.

The Scoping Memo requires that utilities assume that they are responsible for planning for all existing bundled customers and associated load growth, and all new customers resulting from economic growth in their service areas. The Scoping Memo also specifies that utilities should assume that in the long-term they are responsible for the new resource planning for non-RPS generation for the DA and CCA loads in their service territory.[58] Given the uncertainty associated with DA departure or return, and

[57] *See* CPUC's community choice aggregation report to the California Legislature, submitted pursuant to AB 117, January 2006.

[58] Scoping Memo, Attachment A at 13.

with the potential CCA departure, PG&E uses different levels of DA and CCA migration in its evaluation of alternative procurement plans.

(7) Recontracting of Existing Qualifying Facilities, Irrigation District Contracts, and Renewable Portfolio Standard Bilateral Contracts

For purposes of determining resource need in NP26, PG&E assumes that existing resources currently under contract with PG&E remain in operation at their contract expiration. However, for purposes of estimating the portfolio's procurement need, PG&E assumes the amount of existing resources it is able to re-contract varies depending on the availability of CCA, DA, and non-core options to customers. That is, when customers choose DA, CCA and non-core options, PG&E assumes fewer of its existing contracts will recontract to PG&E.

c. Long-Term Commercial Uncertainties

Long-term commercial uncertainties include regulatory delays, delays in project construction, project failures and delays in transmission projects. All of these uncertainties can have a significant effect on PG&E's portfolio. For example, delay in a single project could result in 500 MW of energy forecasted for a certain year being unavailable. In order to capture the uncertainty associated with the commercial operation of the new generation projects, PG&E assumed that a 500 MW resource, one of the proposed combined cycle resources, is cancelled or delayed.

2. Scenarios

To evaluate uncertainties, PG&E developed four scenarios that it used to test its candidate plans. Each candidate plan was tested under each scenario to determine how the plan performed. The four scenarios are described in detail in Volume 1, Section IV.A.1.

E. Regional Need Determination (Residual Net Long/Short Forecast)

This section describes the anticipated need for new physical resources in the CAISO NP26 region. PG&E's NP26 regional analysis is based on the ability of the CAISO NP26 region to meet planning reserve requirements in the region. To capture the supply and demand uncertainties within the region, a range of need was analyzed under a series of different scenario supply and demand assumptions. The PG&E service area capacity need is its proportionate share, based on a peak load basis, of the CAISO NP26 region need.

PG&E examined the CAISO NP26 supply demand capacity situation under the four scenarios described in Volume 1, Section IV. A.1. The analysis looks at both a planning reserve based on a 1-in-2 summer temperature demand and 15% Planning Reserve Margin, as well as a 1-in-10 summer temperature demand with a 16% Planning Reserve Margin. The second case shows the increased need resulting from a higher planning reserve criteria. The following section describes the supply, demand and planning reserve assumptions used to derive the need for new resources required to maintain planning and operating reserves.

1. Supply Assumptions

a. Existing Generation and Resource Adequacy Adjustment

The CEC's Supply/Demand 5-year outlook[59] is the source for the 2007 base amount of existing generation resources in NP26. The amount of existing resources in the NP26 region is based on Resource Accounting Rules and is consistent in all four scenarios (Tables Vol. 1, IVE 1-4, Line 1). For two of the scenarios (Scenarios 2 and 4), PG&E has included a 500 MW reduction in the RA value of resources beginning in 2009 to account for the potential adjustment to the RA counting rules as explained in Volume 1, Section IV.D.1.b. (Tables Vol. 1, IVE 2 and 4, Line 2).

The CEC only considers known retirements in its 5-year outlook analysis. PG&E placed retirements into two categories. The first category (Tables Vol. 1, IVE 1-4, Line 3) includes units that have announced retirement dates. This category includes the projected retirements of the existing facilities at PG&E's HBPP. The second category (Tables Vol. 1, IVE 1-4, Line 4) identifies units that may retire in the 2007-2016 time period. For this category, PG&E includes 4,374 MW from units identified in the *2004 CEC Staff Draft Report 100-04-005D Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*. Scenarios 3 and 4 assume that all 4,374 MW retire by 2012, corresponding to the CEC goal of having aging plants retired by 2012. Scenarios 1 and 2 assume that the plants retire on a slower schedule, with all aging plants retired by 2015.

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[59] CEC's *Revised Summer 2006 Demand and Supply Five Year Outlook*, June 30, 2006.

b. Generation Additions

The CEC only considers high probability additions of new California generation in its analysis. PG&E separates generation additions into three categories: renewable resources that will increase from ongoing RPS requirements, non-RPS planned additions developed through PG&E's procurement process, and high probability additions expected to be on-line in the region.

The NP26 RPS additions line reflects the capacity from future renewable generation additions. This includes generation procured by PG&E in its 2004 and 2005 RPS solicitations expected to become operational during the planning horizon and renewable additions based on the market availability of renewable resources to the NP26 region. The market availability of renewable resources is commensurate with the MWh amounts described in PG&E's RPS Plan for its bundled customers in Volume 1, Section IV.C.2. To account for the renewable resources available to POU customers within the NP26 region, the market availability of renewables is estimated to be 7.4% over the market availability for PG&E bundled load on an energy basis. (Tables Vol. 1, IVE 1-4, Line 5). By 2016, the total NP26 region RPS amounts vary from 1,528 MW in Scenario 1 to 1,870 MW in Scenario 4.

PG&E planned additions include the proposed winning bid resource additions (including plants in the Bay Area, Central Valley and Humboldt regions) from PG&E's 2004 LTRFO, along with CC8. In Scenarios 1-3, these PG&E planned additions (Tables Vol. 1, IVE 1-3, Line 6) result in an additional 2,851 MW in the region by 2010. Due to uncertainties regarding the development schedules of all resource additions in PG&E's plan, Scenario 4 assumes that the amount of megawatts realized from these additions is 600 MW less (Table Vol. 1, IVE 4, Line 6) than the amounts considered in Scenarios 1, 2 and 3.

High Probability California additions (Tables Vol. 1, IVE 1-4, Line 7) represent approved new generating units in the region with an expected on-line date controlled by others than PG&E. All scenarios include the 180 MW SF peaker project, which is identified as a high probability addition. The generation from this project is shown beginning in 2009.

c. Net Interchange

The Net Interchange into the NP26 region is based on several components with the composite total shown on Line 12 of Tables Vol. 1, IVE 1-4. The first component includes 2,348 MWs of Northwest imports based on the CAISO estimate of import levels for RA[60] (Tables Vol. 1, IVE 1-4, Line 8). Additional imports from WAPA to public entities within the CAISO NP26 region are estimated to be 700 MW (Tables Vol. 1, IVE 1-4, Line 9). Next, the NW imports are decreased to account for potential NW RPS imports already accounted for in (Tables Vol. 1, IVE 1-4, Line 5), as the NP26 RPS additions estimate includes potential Northwest renewable projects. These adjustments increase to as much as 172 MW by 2016 depending on the scenario (Tables Vol. 1, IVE 1-4, Line 10). The exports to CAISO Southern Region are based on the CEC 2006 Summer Outlook[61] assumption of 3,000 MW (Tables Vol. 1, IVE 1-4, Line 11).

d. Demand Response

For purposes of this regional capacity analysis, DR programs are treated as supply resources.[62] DR (Tables Vol. 1, IVE 1-4, Lines 13 and 14) is split into two areas: Price Sensitive Demand Response and Interruptible/Curtailable Programs. The Price Sensitive Demand Response includes existing price responsive programs and the additional projected DR from the deployment of AMI, as described in Volume 1, Section IV.C.1. Scenarios 1 and 2 show these programs growing from 342 MW in 2007 to 531 MW in 2016. Scenarios 3 and 4 show a larger growth, from 342 MW in 2007 to 801 MW in 2016.

Interruptible/Curtailable programs reflect existing DR programs. Details on these programs are described in Volume 1, Section IV.C. These existing programs are forecast to increase from 310 MW in 2007 to 353 MW in 2008 through 2016 (Tables Vol. 1, IVE 1-4, Line 14).

2. Demand Assumptions

The CAISO NP26 demand assumptions are primarily based on recent information published by the CEC with adjustments to reflect information consistent with recent PG&E filings. The adjusted 1-in-2 summer temperature demand for each scenario is shown on Line 21 of Tables Vol. 1, IVE 1-4. The following sections describe the demand assumptions used in the capacity need analysis.

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[60] Supplemental Deliverability Study: Import Levels for Resource Adequacy (RA) Planning Purposes http://www.caiso.com/docs/2005/09/23/20050923165719616.pdf.

[61] CEC's *Revised Summer 2006 Demand and Supply Five Year Outlook*, June 30, 2006.

[62] The additional effect of these resources in reducing reserves is described below in Volume 1, Section IV.E.2.d.

a. 1-in-2 Summer Temperature Demand (Normal)

One uncertainty in the peak demand load forecast arises from unknown future economic conditions in the state. For 2007, all four scenarios use the CAISO NP26 peak demand of 21,098 MW from the CEC's Summer 2006 Demand and Supply Five Year Outlook. Forecast year-by-year peak demands (Tables Vol. 1, IVE 1-4, Line 16) are then calculated consistent with the peak demand growth rates associated with each scenario described in Volume 1, Section IV.B.

b. Uncommitted Energy Efficiency

The regional capacity tables show the regional peak MW reduction, consistent with RA accounting, from market available EE (Tables Vol. 1, IVE 1-4, Line 17). Megawatt reductions associated with PG&E's 2006-2008 EE plan portfolio are not included as they are included in each scenario's demand forecast. To reflect potential EE from other regional entities, the PG&E uncommitted EE forecasts consistent with the market availabilities described in Volume 1, Section IV.C, for each scenario, are increased from 9 to 11 MW depending on year and scenario. By 2016, uncommitted EE ranges from 1,487 MW in Scenario 1 to 2,195 MW in Scenario 4.

c. Distributed Generation

Future distributed generation not captured in the load forecast is shown in the lines entitled CA Solar Initiative and DG-CHP & Other (Tables Vol. 1, IVE 1-4, Lines 18 and 19).

The California Solar Initiative, established by D.06-01-024, will result in new solar generation in the NP26 region. The capacity included from these resources is consistent with RA counting rules using installed capacity reduced by a shaping factor representative of availability during peak time periods. The four forecasts of CSI are consistent with those described in Volume 1, Section IV.C. The amount of CSI in 2016 ranges from 140 MW in Scenario 1 to 600 MW in Scenario 4.

The load reduction from CHP and other self-generation, consistent with Volume 1, Section IV.C, is captured in the DG-CHP and Other category. The forecast for this category is the same for all four scenarios, ranging from 36 MW in 2007 to 361 MW in 2016.

d. Loss Adjustment From Demand Reduction

Reductions in peak demand also result in lower amounts of Unaccounted for Energy ("UFE") and Transmission and Distribution ("T&D") losses. The decreased losses are related to the amount and timing of peak demand reductions in each scenario (Tables Vol. 1, IVE 1-4, Line 20). The loss factors used to develop this adjustment are the same as those used to develop each scenario's peak load forecast described in Volume 1, Section IV.B.

3. 1-in-2 Summer Temperature Demand Planning Reserves

Planning reserves are resources in excess of peak demand that are available to meet short-term uncertainties such as higher than expected demand due to hot weather events and unavailability of resources due to outages. The year-by-year Planning Reserve is calculated by subtracting the Adjusted 1-in-2 summer temperature demand from the Total Net Resources (Tables Vol. 1, IVE 1-4, Line 22). The year-by-year Planning Reserve percentage (Tables Vol. 1, IVE 1-4, Line 23) is calculated by dividing the Planning Reserve by the Adjusted 1-in-2 summer temperature demand.

For RA purposes, a planning reserve of 15-17% has been adopted by the Commission. In this analysis of regional need, PG&E calculates planning reserve requirement based on a 15% requirement (Tables Vol. 1, IVE 1-4, Line 24). A Net Planning Reserve requirement (Tables Vol. 1, IVE 1-4, Line 27) is calculated by adjusting the Planning Reserve Requirement to account for the reserve credits for the DR programs (Tables Vol. 1, IVE 1-4, Lines 25 and 26) that are treated as supply resources for RA purposes.

The Surplus/Deficit of the CAISO NP26 region (Tables Vol. 1, IVE 1-4, Line 28) is calculated as the difference between the Planning Reserve and the Net Planning Reserve Requirement. A positive number is indicative of available resources within the CAISO NP26 region sufficient to maintain a 15% planning reserve. Since PG&E's service territory represents approximately 92% of the CAISO NP26 region load, PG&E's Service Area Need (Tables Vol. 1, IVE 1-4, Line 29) is assumed to be 92% of any CAISO NP26 regional deficit (Tables Vol. 1, IVE 1-4, Line 28).

4. 1-in-10 Summer Temperature Demand Case

In addition to a supply demand analysis based on a 1-in-2 summer temperature demand, PG&E also has analyzed a 1-in-10 summer temperature demand case with a 16% PRM.[63] The following sub-sections describe the demand and planning reserve

[63] PG&E provides support for this higher planning reserve requirement in Volume 2, Section IV.A.

assumptions used to derive the need for new resources required to maintain a 16% planning reserve margin in conjunction with 1-in-10 summer temperature demand.

a. 1-in-10 Summer Temperature Demand Adjustment

The CEC has calculated a scalar factor to capture the increased load when considering a 1-in-10 summer temperature demand. The 1-in-10 summer temperature demand adjustment and resulting adjusted 1-in-10 summer temperature demand for the CAISO NP26 region (Tables Vol. 1, IVE 1-4, Lines 30 and 31) is 2007 is based on this scalar multiplied by the 2007 1-in-2 summer temperature demand of 21,098 MW. Demand in subsequent years is determined using the same percentage growth rates used in the 1-in-2 summer temperature demand case for each scenario.

b. Planning Reserves

In the 1-in-10 summer temperature demand case, PG&E calculates planning reserves and planning reserves percentage based on a 16% PRM (Tables Vol. 1, IVE 1-4, Lines 32 and 33). A Net Planning Reserve requirement (Tables Vol. 1, IVE 1-4, Line 34) is calculated by adjusting the Planning Reserve Requirement to account for the reserve credits for the DR programs (Tables Vol. 1, IVE 1-4, Lines 25 and 26) that are for RA purposes treated as supply resources. Similar to the 1-in-2 summer temperature demand case, the Surplus/Deficit of the CAISO NP26 region (Tables Vol. 1, IVE 1-4, Line 35) is calculated as the difference between the year-by-year Planning Reserve and the Net Planning Reserve Requirement. A positive number is indicative of available resources sufficient to maintain a 16% planning reserve. PG&E's capacity analysis focuses on the need for new resources within the CAISO NP26 region. Since PG&E's service territory represents approximately 92% of the CAISO NP 26 region load, PG&E's Service Area Need (Tables Vol. 1, IVE 1-4, Line 36) is assumed to be 92% of any CAISO NP26 regional deficit (Tables Vol. 1, IVE 1-4, Line 35).

c. Operating Reserves

Operating reserves are resources in excess of peak demand, taking into account forced outages and transmission zonal limitations. The operating reserves section in Tables Vol. 1, IVE 1-4 show operating reserves calculated under two different temperature conditions: 1-in-2 Normal summer temperature demand, and a 1-in-10 summer temperature demand. PG&E selected to analyze a 5% operating reserve criteria as some DR programs are initiated at a 5% operating reserve level.

The outage assumptions of 1,100 MW and zonal transmission limitation of 0 MW shown in Lines 37 and 38 in Tables Vol. 1, IVE 1-4 are consistent with the expected assumptions shown in the CEC's Supply/Demand 5 year outlook for NP26. The sum of these adjustments are then added to the Total Net Resources to determine the expected operating generation with outages and limitations shown in Line 39 in Tables Vol.1, IVE 1-4.

Operating reserve margins for each of the two different summer temperature conditions are shown on Tables Vol. 1, IVE 1-4, Lines 40 and 43. Tables Vol. 1, IVE 1-4, Lines 41 and 44 show the CAISO NP26 resources required to meet a 5% operating reserve margin. A negative number is indicative of resources required to reach a 5% operating margin. PG&E's capacity analysis focuses on the need for new resources within the CAISO NP26 region. Since PG&E's service territory represents approximately 92% of the CAISO NP26 region load, PG&E's Service Area Need (Tables Vol. 1, IVE 1-4, Lines 42 and 45) is assumed to be 92% of any CAISO NP26 regional deficit.

Table Vol.1, IVE - 1
PACIFIC GAS AND ELECTRIC COMPANY
Regional Need (MW)

Scenario-1 CAISO Northern Region (NP26)

	SUPPLY	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
1	Existing Generation	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417
2	RA Adjustment	0	0	0	0	0	0	0	0	0	0
3	Retirements (Known)	0	0	(135)	(135)	(135)	(135)	(135)	(135)	(135)	(135)
4	Retirements (Potential)	0	0	0	(682)	(2,821)	(3,158)	(3,494)	(4,168)	(4,374)	(4,374)
5	NP26 RPS Additions (Including Imports)	28	142	293	621	821	1,001	1,163	1,309	1,441	1,528
6	PG&E Planned Additions	0	0	998	2,851	2,851	2,851	2,851	2,851	2,851	2,851
7	High Probability CA Additions	0	0	180	180	180	180	180	180	180	180
8	NW Imports	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348
9	WAPA Firm Imports	700	700	700	700	700	700	700	700	700	700
10	Adjustment RPS NW Imports	0	(12)	(23)	(40)	(54)	(67)	(79)	(90)	(99)	(102)
11	Exports to SP26	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
12	Net Interchange	48	36	25	8	(6)	(19)	(31)	(42)	(51)	(54)
13	Price Sensitive Demand Response (DR)	342	343	416	484	509	516	519	523	527	531
14	Interruptible/DR Curtailable Programs	310	353	353	353	353	353	353	353	353	353
15	Total Net Resources	25,145	25,292	26,547	28,097	26,169	26,006	25,823	25,288	25,208	25,296
	1-IN-2 SUMMER TEMPERATURE DEMAND CASE										
	DEMAND										
16	1-in-2 Summer Temperature Demand	21,098	21,244	21,661	22,168	22,636	23,117	23,596	24,059	24,574	25,142
17	Uncommitted Energy Efficiency	(8)	(9)	(180)	(365)	(557)	(752)	(948)	(1,136)	(1,316)	(1,487)
18	CA Solar Initiative	(14)	(28)	(42)	(56)	(70)	(84)	(98)	(112)	(126)	(140)
19	DG-CHP & Other	(36)	(72)	(108)	(144)	(180)	(216)	(252)	(289)	(325)	(361)
20	Loss adjustment from DR	(6)	(12)	(36)	(62)	(91)	(121)	(146)	(173)	(201)	(229)
21	Adjusted 1-in-2 Summer Temperature Demand	21,033	21,123	21,296	21,541	21,738	21,944	22,151	22,349	22,607	22,925
	PLANNING RESERVES										
22	Planning Reserve	4,112	4,168	5,251	6,556	4,431	4,062	3,672	2,939	2,601	2,371
23	Planning Reserve [1] (%)	19.5%	19.7%	24.7%	30.4%	20.4%	18.5%	16.6%	13.2%	11.5%	10.3%
24	Planning Reserve Requirement (15%)	3,155	3,169	3,194	3,231	3,261	3,292	3,323	3,352	3,391	3,439
25	Price Sensitive DR reserve credit	(51)	(51)	(62)	(73)	(76)	(77)	(78)	(78)	(79)	(80)
26	Interruptible/DR Curtailable Programs reserve credit	(47)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
27	Net Planning Reserve Requirement	3,057	3,064	3,079	3,106	3,131	3,161	3,192	3,221	3,259	3,306
28	**1 in 2 Surplus/Deficit CA ISO NP 26 Northern Region**	**1,055**	**1,104**	**2,172**	**3,451**	**1,299**	**901**	**480**	**(282)**	**(658)**	**(935)**
29	**1 in 2 PG&E Service Area Need at 92% [2]**	**970**	**1,016**	**1,998**	**3,175**	**1,196**	**829**	**442**	**(259)**	**(605)**	**(860)**
	1-IN-10 SUMMER TEMPERATURE DEMAND CASE										
	DEMAND										
30	1-10 Summer Temperature Demand Adjustment	738	744	758	776	792	809	826	842	860	880
31	Adjusted 1-in-10 Summer Temperature Demand	21,772	21,867	22,054	22,317	22,530	22,753	22,977	23,191	23,467	23,805
	PLANNING RESERVES										
32	Planning Reserve in 1 in 10 case	3,373	3,425	4,493	5,780	3,639	3,253	2,846	2,097	1,741	1,491
33	Planning Reserve in 1 in 10 case [1] (%)	15.5%	15.7%	20.4%	25.9%	16.1%	14.3%	12.4%	9.0%	7.4%	6.3%
34	Net Planning Reserve Margin (16%)	3,379	3,387	3,406	3,437	3,467	3,501	3,537	3,570	3,614	3,667
35	**1 in 10 Surplus/Deficit CA ISO NP 26 Northern Region**	**(6)**	**37**	**1,087**	**2,344**	**172**	**(248)**	**(691)**	**(1,473)**	**(1,873)**	**(2,176)**
36	**1 in 10 PG&E Service Area Need at 92% [2]**	**(5)**	**34**	**1,000**	**2,156**	**158**	**(229)**	**(636)**	**(1,355)**	**(1,723)**	**(2,002)**
	OPERATING RESERVES										
37	Outages	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)
38	Zonal transmission limitation	0	0	0	0	0	0	0	0	0	0
39	Expected Operating Generation with Outages/Limitations	24,045	24,192	25,447	26,997	25,069	24,906	24,723	24,188	24,108	24,196
	EXPECTED 1-IN-2 SUMMER DEMAND CONDITIONS										
40	Expected Operating Reserve [3] (%)	14.4%	14.6%	19.5%	25.3%	15.3%	13.5%	11.6%	8.2%	6.6%	5.5%
41	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
42	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	ADVERSE 1-IN-10 SUMMER TEMPERATURE DEMAND CONDITIONS										
43	1-10 Summer Temperature Demand Operating Reserve [3] (%)	10.5%	10.6%	15.4%	21.0%	11.3%	9.5%	7.6%	4.3%	2.7%	1.6%
44	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(164)**	**(535)**	**(802)**
45	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(151)**	**(492)**	**(738)**

1 Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

2 PG&E Service Area Need: (PG&E Bundled Customer + PG&E Direct Access)/CA ISO NP26 Demand

3 Operating Reserve: ((Operating Generation-Net Interchange+Demand Response+Interruptibles)/(Normal Demand-Net Interchange+Summer Termperature Demand Adjustment)-1.

Table Vol.1, IVE - 2
PACIFIC GAS AND ELECTRIC COMPANY
Regional Need (MW)

Scenario-2 CAISO Northern Region (NP26)											
SUPPLY		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
1	Existing Generation	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417
2	RA Adjustment	0	0	-500	-500	-500	-500	-500	-500	-500	-500
3	Retirements (Known)	0	0	(135)	(135)	(135)	(135)	(135)	(135)	(135)	(135)
4	Retirements (Potential)	0	0	0	(682)	(2,821)	(3,158)	(3,494)	(4,168)	(4,374)	(4,374)
5	NP26 RPS Additions (Including Imports)	28	142	293	628	857	1,087	1,316	1,546	1,664	1,782
6	PG&E Planned Additions	0	0	998	2,851	2,851	2,851	2,851	2,851	2,851	2,851
7	High Probability CA Additions	0	0	180	180	180	180	180	180	180	180
8	NW Imports	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348
9	WAPA Firm Imports	700	700	700	700	700	700	700	700	700	700
10	Adjustment RPS NW Imports	0	(12)	(23)	(41)	(58)	(76)	(93)	(110)	(128)	(145)
11	Exports to SP26	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
12	Net Interchange	48	36	25	7	(10)	(28)	(45)	(62)	(80)	(97)
13	Price Sensitive Demand Response (DR)	342	343	416	484	509	516	519	523	527	531
14	Interruptible/DR Curtailable Programs	310	353	353	353	353	353	353	353	353	353
15	Total Net Resources	25,145	25,292	26,047	27,603	25,701	25,583	25,462	25,004	24,903	25,007
1-IN-2 SUMMER TEMPERATURE DEMAND CASE											
DEMAND											
16	1-in-2 Summer Temperature Demand	21,098	21,307	21,790	22,366	22,906	23,461	24,019	24,563	25,163	25,820
17	Uncommitted Energy Efficiency	(8)	(9)	(187)	(382)	(588)	(789)	(991)	(1,192)	(1,381)	(1,570)
18	CA Solar Initiative	(17)	(38)	(59)	(80)	(101)	(122)	(143)	(164)	(185)	(206)
19	DG-CHP & Other	(36)	(72)	(108)	(144)	(180)	(216)	(252)	(289)	(325)	(361)
20	Loss adjustment from DR	(6)	(12)	(37)	(64)	(93)	(121)	(150)	(179)	(207)	(235)
21	Adjusted 1-in-2 Summer Temperature Demand	21,030	21,176	21,399	21,696	21,943	22,213	22,483	22,741	23,067	23,449
PLANNING RESERVES											
22	Planning Reserve	4,115	4,116	4,648	5,907	3,758	3,370	2,980	2,264	1,836	1,559
23	Planning Reserve [1] (%)	19.6%	19.4%	21.7%	27.2%	17.1%	15.2%	13.3%	10.0%	8.0%	6.6%
24	Planning Reserve Requirement (15%)	3,155	3,176	3,210	3,254	3,292	3,332	3,372	3,411	3,460	3,517
25	Price Sensitive DR reserve credit	(51)	(51)	(62)	(73)	(76)	(77)	(78)	(78)	(79)	(80)
26	Interruptible/DR Curtailable Programs reserve credit	(47)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
27	Net Planning Reserve Requirement	3,057	3,072	3,094	3,129	3,162	3,202	3,242	3,280	3,328	3,385
28	**1 in 2 Surplus/Deficit CA ISO NP 26 Northern Region**	**1,058**	**1,044**	**1,553**	**2,778**	**595**	**169**	**(262)**	**(1,016)**	**(1,492)**	**(1,826)**
29	**1 in 2 PG&E Service Area Need at 92% [2]**	**973**	**960**	**1,429**	**2,556**	**548**	**155**	**(241)**	**(935)**	**(1,372)**	**(1,680)**
1-IN-10 SUMMER TEMPERATURE DEMAND CASE											
DEMAND											
30	1-10 Summer Temperature Demand Adjustment	738	746	763	783	802	821	841	860	881	904
31	Adjusted 1-in-10 Summer Temperature Demand	21,769	21,922	22,161	22,478	22,745	23,034	23,323	23,601	23,947	24,352
PLANNING RESERVES											
32	Planning Reserve in 1 in 10 case	3,376	3,370	3,885	5,124	2,956	2,549	2,139	1,404	956	655
33	Planning Reserve in 1 in 10 case [1] (%)	15.5%	15.4%	17.5%	22.8%	13.0%	11.1%	9.2%	5.9%	4.0%	2.7%
34	Net Planning Reserve Margin (16%)	3,379	3,396	3,423	3,463	3,501	3,546	3,592	3,636	3,691	3,755
35	**1 in 10 Surplus/Deficit CA ISO NP 26 Northern Region**	**(3)**	**(26)**	**462**	**1,662**	**(545)**	**(997)**	**(1,453)**	**(2,232)**	**(2,735)**	**(3,100)**
36	**1 in 10 PG&E Service Area Need at 92% [2]**	**(2)**	**(24)**	**425**	**1,529**	**(502)**	**(918)**	**(1,337)**	**(2,054)**	**(2,516)**	**(2,852)**
OPERATING RESERVES											
37	Outages	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)
38	Zonal transmission limitation	0	0	0	0	0	0	0	0	0	0
39	Expected Operating Generation with Outages/Limitations	24,045	24,192	24,947	26,503	24,601	24,483	24,362	23,904	23,803	23,907
EXPECTED 1-IN-2 SUMMER DEMAND CONDITIONS											
40	Expected Operating Reserve [3] (%)	14.4%	14.3%	16.6%	22.2%	12.1%	10.2%	8.3%	5.1%	3.2%	1.9%
41	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(421)**	**(718)**
42	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(387)**	**(661)**
ADVERSE 1-IN-10 SUMMER TEMPERATURE DEMAND CONDITIONS											
43	1-10 Summer Temperature Demand Operating Reserve [3] (%)	10.5%	10.4%	12.6%	17.9%	8.2%	6.3%	4.4%	1.3%	-0.6%	-1.8%
44	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**0**	**(129)**	**(879)**	**(1,346)**	**(1,667)**
45	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**0**	**(119)**	**(809)**	**(1,238)**	**(1,534)**

1 Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

2 PG&E Service Area Need: (PG&E Bundled Customer + PG&E Direct Access)/CA ISO NP26 Demand

3 Operating Reserve: ((Operating Generation-Net Interchange+Demand Response+Interruptibles)/(Normal Demand-Net Interchange+Summer Termperature Demand Adjustment)-1.

Table Vol.1, IVE - 3
PACIFIC GAS AND ELECTRIC COMPANY
Regional Need (MW)

Scenario-3 CAISO Northern Region (NP26)

	SUPPLY	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
1	Existing Generation	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417
2	RA Adjustment	0	0	0	0	0	0	0	0	0	0
3	Retirements (Known)	0	0	(135)	(135)	(135)	(135)	(135)	(135)	(135)	(135)
4	Retirements (Potential)	0	0	0	(682)	(2,821)	(4,374)	(4,374)	(4,374)	(4,374)	(4,374)
5	NP26 RPS Additions (Including Imports)	28	142	293	628	857	1,087	1,316	1,546	1,664	1,782
6	PG&E Planned Additions	0	0	998	2,851	2,851	2,851	2,851	2,851	2,851	2,851
7	High Probability CA Additions	0	0	180	180	180	180	180	180	180	180
8	NW Imports	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348
9	WAPA Firm Imports	700	700	700	700	700	700	700	700	700	700
10	Adjustment RPS NW Imports	0	(12)	(23)	(41)	(58)	(76)	(93)	(110)	(128)	(145)
11	Exports to SP26	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
12	Net Interchange	48	36	25	7	(10)	(28)	(45)	(62)	(80)	(97)
13	Price Sensitive Demand Response (DR)	342	394	554	695	750	765	774	783	792	801
14	Interruptible/DR Curtailable Programs	310	353	353	353	353	353	353	353	353	353
15	Total Net Resources	25,145	25,343	26,685	28,314	26,442	25,116	25,337	25,558	25,668	25,777
	1-IN-2 SUMMER TEMPERATURE DEMAND CASE										
	DEMAND										
16	1-in-2 Summer Temperature Demand	21,098	21,307	21,790	22,366	22,906	23,461	24,019	24,563	25,163	25,820
17	Uncommitted Energy Efficiency	(8)	(9)	(187)	(382)	(588)	(789)	(991)	(1,192)	(1,381)	(1,570)
18	CA Solar Initiative	(17)	(38)	(65)	(95)	(126)	(158)	(190)	(223)	(256)	(291)
19	DG-CHP & Other	(36)	(72)	(108)	(144)	(180)	(216)	(252)	(289)	(325)	(361)
20	Loss adjustment from DR	(6)	(12)	(38)	(66)	(95)	(125)	(154)	(184)	(213)	(244)
21	Adjusted 1-in-2 Summer Temperature Demand	21,030	21,176	21,392	21,678	21,915	22,173	22,431	22,676	22,988	23,355
	PLANNING RESERVES										
22	Planning Reserve	4,115	4,167	5,293	6,636	4,527	2,943	2,906	2,882	2,680	2,422
23	Planning Reserve [1] (%)	19.6%	19.7%	24.7%	30.6%	20.7%	13.3%	13.0%	12.7%	11.7%	10.4%
24	Planning Reserve Requirement (15%)	3,155	3,176	3,209	3,252	3,287	3,326	3,365	3,401	3,448	3,503
25	Price Sensitive DR reserve credit	(51)	(59)	(83)	(104)	(113)	(115)	(116)	(117)	(119)	(120)
26	Interruptible/DR Curtailable Programs reserve credit	(47)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
27	Net Planning Reserve Requirement	3,057	3,064	3,073	3,095	3,122	3,158	3,196	3,231	3,277	3,330
28	**1 in 2 Surplus/Deficit CA ISO NP 26 Northern Region**	**1,058**	**1,102**	**2,220**	**3,541**	**1,405**	**(215)**	**(289)**	**(349)**	**(597)**	**(908)**
29	**1 in 2 PG&E Service Area Need at 92% [2]**	**973**	**1,014**	**2,043**	**3,258**	**1,292**	**(198)**	**(266)**	**(321)**	**(549)**	**(835)**
	1-IN-10 SUMMER TEMPERATURE DEMAND CASE										
	DEMAND										
30	1-10 Summer Temperature Demand Adjustment	738	746	763	783	802	821	841	860	881	904
31	Adjusted 1-in-10 Summer Temperature Demand	21,769	21,922	22,154	22,461	22,717	22,994	23,271	23,536	23,869	24,259
	PLANNING RESERVES										
32	Planning Reserve in 1 in 10 case	3,376	3,421	4,530	5,853	3,725	2,122	2,066	2,022	1,799	1,518
33	Planning Reserve in 1 in 10 case [1] (%)	15.5%	15.6%	20.4%	26.1%	16.4%	9.2%	8.9%	8.6%	7.5%	6.3%
34	Net Planning Reserve Margin (16%)	3,379	3,388	3,400	3,426	3,458	3,500	3,543	3,584	3,636	3,697
35	**1 in 10 Surplus/Deficit CA ISO NP 26 Northern Region**	**(3)**	**33**	**1,131**	**2,427**	**267**	**(1,378)**	**(1,477)**	**(1,562)**	**(1,837)**	**(2,178)**
36	**1 in 10 PG&E Service Area Need at 92% [2]**	**(2)**	**30**	**1,040**	**2,232**	**245**	**(1,268)**	**(1,359)**	**(1,437)**	**(1,690)**	**(2,004)**
	OPERATING RESERVES										
37	Outages	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)
38	Zonal transmission limitation	0	0	0	0	0	0	0	0	0	0
39	Expected Operating Generation with Outages/Limitations	24,045	24,243	25,585	27,214	25,342	24,016	24,237	24,458	24,568	24,677
	EXPECTED 1-IN-2 SUMMER DEMAND CONDITIONS										
40	Expected Operating Reserve [3] (%)	14.4%	14.5%	19.6%	25.5%	15.6%	8.3%	8.0%	7.8%	6.8%	5.6%
41	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
42	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	ADVERSE 1-IN-10 SUMMER TEMPERATURE DEMAND CONDITIONS										
43	1-10 Summer Temperature Demand Operating Reserve [3] (%)	10.5%	10.6%	15.5%	21.2%	11.5%	4.4%	4.1%	3.9%	2.9%	1.7%
44	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**(129)**	**(200)**	**(258)**	**(499)**	**(799)**
45	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**(119)**	**(184)**	**(237)**	**(459)**	**(735)**

1 Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

2 PG&E Service Area Need: (PG&E Bundled Customer + PG&E Direct Access)/CA ISO NP26 Demand

3 Operating Reserve: ((Operating Generation-Net Interchange+Demand Response+Interruptibles)/(Normal Demand-Net Interchange+Summer Termperature Demand Adjustment)-1.

Table Vol.1, IVE - 4
PACIFIC GAS AND ELECTRIC COMPANY
Regional Need (MW)

Scenario-4 CAISO Northern Region (NP26)

	SUPPLY	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Existing Generation	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417	24,417
2	RA Adjustment	0	0	-500	-500	-500	-500	-500	-500	-500	-500
3	Retirements (Known)	0	0	(135)	(135)	(135)	(135)	(135)	(135)	(135)	(135)
4	Retirements (Potential)	0	0	0	(682)	(2,821)	(4,374)	(4,374)	(4,374)	(4,374)	(4,374)
5	NP26 RPS Additions (Including Imports)	28	142	293	635	895	1,181	1,496	1,609	1,733	1,870
6	PG&E Planned Additions	0	0	998	2,251	2,251	2,251	2,251	2,251	2,251	2,251
7	High Probability CA Additions	0	0	180	180	180	180	180	180	180	180
8	NW Imports	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348	2,348
9	WAPA Firm Imports	700	700	700	700	700	700	700	700	700	700
10	Adjustment RPS NW Imports	0	(12)	(23)	(42)	(62)	(85)	(110)	(128)	(149)	(172)
11	Exports to SP26	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
12	Net Interchange	48	36	25	6	(14)	(37)	(62)	(80)	(101)	(124)
13	Price Sensitive Demand Response (DR)	342	394	554	695	750	765	774	783	792	801
14	Interruptible/DR Curtailable Programs	310	353	353	353	353	353	353	353	353	353
15	Total Net Resources	25,145	25,343	26,185	27,220	25,375	24,101	24,400	24,504	24,616	24,739
	1-IN-2 SUMMER TEMPERATURE DEMAND CASE										
	DEMAND										
16	1-in-2 Summer Temperature Demand	21,098	21,370	21,920	22,565	23,178	23,810	24,448	25,077	25,765	26,515
17	Uncommitted Energy Efficiency	(8)	(9)	(214)	(419)	(650)	(916)	(1,218)	(1,532)	(1,860)	(2,195)
18	CA Solar Initiative	(17)	(38)	(65)	(99)	(142)	(193)	(259)	(347)	(457)	(600)
19	DG-CHP & Other	(36)	(72)	(108)	(144)	(180)	(216)	(252)	(289)	(325)	(361)
20	Loss adjustment from DR	(6)	(12)	(41)	(70)	(103)	(140)	(184)	(231)	(282)	(338)
21	Adjusted 1-in-2 Summer Temperature Demand	21,030	21,239	21,492	21,832	22,102	22,344	22,534	22,678	22,842	23,021
	PLANNING RESERVES										
22	Planning Reserve	4,115	4,103	4,692	5,387	3,273	1,757	1,866	1,825	1,774	1,718
23	Planning Reserve [1] (%)	19.6%	19.3%	21.8%	24.7%	14.8%	7.9%	8.3%	8.0%	7.8%	7.5%
24	Planning Reserve Requirement (15%)	3,155	3,186	3,224	3,275	3,315	3,352	3,380	3,402	3,426	3,453
25	Price Sensitive DR reserve credit	(51)	(59)	(83)	(104)	(113)	(115)	(116)	(117)	(119)	(120)
26	Interruptible/DR Curtailable Programs reserve credit	(47)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
27	Net Planning Reserve Requirement	3,057	3,074	3,088	3,118	3,150	3,184	3,211	3,231	3,255	3,280
28	**1 in 2 Surplus/Deficit CA ISO NP 26 Northern Region**	**1,058**	**1,030**	**1,605**	**2,269**	**123**	**(1,427)**	**(1,345)**	**(1,406)**	**(1,480)**	**(1,562)**
29	**1 in 2 PG&E Service Area Need at 92% [2]**	**973**	**947**	**1,476**	**2,088**	**114**	**(1,313)**	**(1,238)**	**(1,293)**	**(1,362)**	**(1,437)**
	1-IN-10 SUMMER TEMPERATURE DEMAND CASE										
	DEMAND										
30	1-10 Summer Temperature Demand Adjustment	738	748	767	790	811	833	856	878	902	928
31	Adjusted 1-in-10 Summer Temperature Demand	21,769	21,987	22,259	22,622	22,913	23,178	23,390	23,556	23,744	23,949
	PLANNING RESERVES										
32	Planning Reserve in 1 in 10 case	3,376	3,356	3,925	4,597	2,462	923	1,010	948	873	790
33	Planning Reserve in 1 in 10 case [1] (%)	15.5%	15.3%	17.6%	20.3%	10.7%	4.0%	4.3%	4.0%	3.7%	3.3%
34	Net Planning Reserve Margin (16%)	3,379	3,398	3,416	3,452	3,490	3,530	3,562	3,587	3,616	3,647
35	**1 in 10 Surplus/Deficit CA ISO NP 26 Northern Region**	**(3)**	**(43)**	**509**	**1,145**	**(1,028)**	**(2,606)**	**(2,552)**	**(2,639)**	**(2,743)**	**(2,857)**
36	**1 in 10 PG&E Service Area Need at 92% [2]**	**(2)**	**(39)**	**468**	**1,054**	**(945)**	**(2,398)**	**(2,348)**	**(2,428)**	**(2,524)**	**(2,628)**
	OPERATING RESERVES										
37	Outages	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)
38	Zonal transmission limitation	0	0	0	0	0	0	0	0	0	0
39	Expected Operating Generation with Outages/Limitations	24,045	24,243	25,085	26,120	24,275	23,001	23,300	23,404	23,516	23,639
	EXPECTED 1-IN-2 SUMMER DEMAND CONDITIONS										
40	Expected Operating Reserve [3] (%)	14.4%	14.2%	16.7%	19.6%	9.8%	2.9%	3.4%	3.2%	2.9%	2.7%
41	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**(462)**	**(364)**	**(412)**	**(473)**	**(539)**
42	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**(425)**	**(335)**	**(379)**	**(435)**	**(496)**
	ADVERSE 1-IN-10 SUMMER TEMPERATURE DEMAND CONDITIONS										
43	1-10 Summer Temperature Demand Operating Reserve [3] (%)	10.5%	10.3%	12.7%	15.5%	5.9%	-0.8%	-0.4%	-0.6%	-1.0%	-1.3%
44	**Resources needed to meet 5% Operating Reserve Margin, CA ISO NP26**	**0**	**0**	**0**	**0**	**0**	**(1,337)**	**(1,262)**	**(1,334)**	**(1,420)**	**(1,513)**
45	**Resources needed to meet 5% Operating Reserve Margin, PG&E Service Area**	**0**	**0**	**0**	**0**	**0**	**(1,230)**	**(1,161)**	**(1,227)**	**(1,306)**	**(1,392)**

1 Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

2 PG&E Service Area Need: (PG&E Bundled Customer + PG&E Direct Access)/CA ISO NP26 Demand

3 Operating Reserve: ((Operating Generation-Net Interchange+Demand Response+Interruptibles)/(Normal Demand-Net Interchange+Summer Termperature Demand Adjustment)-1.

5. Summary of Results

The estimated PG&E service area need within the CAISO NP26 region for additional resources is highly dependent on the supply and demand assumptions in each of the four scenarios as well as the assumptions of the planning reserve criteria. PG&E's estimated service area need with planning reserve criteria based on a 1-in-2 summer temperature demand and 15% planning reserve margin is approximately 1,300 MW in 2012-2014 timeframe and growing to 1,700 MW in 2016. With planning reserve criteria based on a 1-in-10 summer temperature demand and 16% planning reserve margin, the PG&E service area need is higher. In this case, PG&E's service area shows a small need in 2007 and 2008. The need grows to 900 MW in 2011, transitioning to 2,400 MW in 2012-2014 timeframe and finally moving to almost 2,900 MW in 2016.

The result of PG&E's analysis of the need in the years 2007 through 2016 for each of the scenarios with a planning reserve margin based on a 1-in-2 summer temperature demand and 15% planning reserve margin is shown in Table Vol. 1, IVE-5, below. Additional resources are needed as early as 2012 based on a 1-in-2 temperature demand and 15% planning reserve margin. Scenario 4 shows a need of approximately 1,300 MW in 2012 as PG&E's share of new resources to meet a 15% planning reserve margin. By 2014, all scenarios show a need for new resources with the need growing through the rest of forecast. The largest need shown in the forecast is approximately 1,700 MW shown in 2016 in Scenario 2.

TABLE VOL. 1, IVE-5
PACIFIC GAS AND ELECTRIC COMPANY
PG&E SERVICE AREA NEED BASED ON 1-IN-2 SUMMER TEMPERATURE DEMAND AND 15% PLANNING RESERVE MARGIN
(MW)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Scenario 1	–	–	–	–	–	–	–	(259)	(605)	(860)
2	Scenario 2	–	–	–	–	–	–	(241)	(935)	(1,373)	(1,680)
3	Scenario 3	–	–	–	–	–	(198)	(266)	(321)	(549)	(835)
4	Scenario 4	–	–	–	–	–	(1,313)	(1,238)	(1,293)	(1,362)	(1,437)

Negative numbers represent Peak MW needed to meet PG&E's share of new resources to meet 15% planning reserve.

The result of PG&E's analysis of the need in the years 2007 through 2016 for each of the scenarios with a planning reserve margin based on a 1-in-10 summer temperature demand and 16% planning reserve margin is shown in Table Vol. 1, IVE-6 below. Scenarios 2 and 4 show a small need in 2008. By 2012 all scenarios show a need for new resources with the largest need occurring in 2016 in Scenario 2 of approximately 2,900 MW.

TABLE VOL. 1, IVE-6
PACIFIC GAS AND ELECTRIC COMPANY
PG&E SERVICE AREA NEED BASED ON 1-IN-10 SUMMER TEMPERATURE DEMAND AND 16% PLANNING RESERVE MARGIN
(MW)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Scenario 1	(5)	–	–	–	–	(229)	(636)	(1,355)	(1,723)	(2,002)
2	Scenario 2	(2)	(24)	–	–	(502)	(918)	(1,337)	(2,054)	(2,516)	(2,852)
3	Scenario 3	(2)	–	–	–	–	(1,268)	(1,359)	(1,437)	(1,690)	(2,004)
4	Scenario 4	(2)	(39)	–	–	(945)	(2,398)	(2,348)	(2,428)	(2,524)	(2,628)

Negative numbers represent Peak MW needed to meet PG&E's share of new resources to meet 16% planning reserve.

PG&E's share of resources needed to meet a 5% operating reserve margin is highly dependent on the summer temperature demand conditions considered. In all four scenarios, resources are not needed to meet a 5% operating reserve margin until 2012 under 1-in-2 summer demand conditions and under adverse 1-in-10 summer demand conditions. Table Vol. 1, IVE-7 below shows PG&E's share of new resources to meet a 5% operating reserve margin.

TABLE VOL. 1, IVE-7
PACIFIC GAS AND ELECTRIC COMPANY
PG&E SERVICE AREA SHARE OF RESOURCES NEEDED TO MEET 5% OPERATING RESERVE (MW)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	1-in-2 Summer Demand										
2	Scenario 1	–	–	–	–	–	–	–	–	–	–
3	Scenario 2	–	–	–	–	–	–	–	–	(387)	(661)
4	Scenario 3	–	–	–	–	–	–	–	–	–	–
5	Scenario 4	–	–	–	–	–	(425)	(335)	(379)	(435)	(496)
6	1-in-10 Summer Demand										
7	Scenario 1			–	–	–	–	–	(151)	(492)	(738)
8	Scenario 2	–	–	–	–	–	–	(119)	(809)	(1,238)	(1,534)
9	Scenario 3	–	–	–	–	–	(119)	(184)	(237)	(459)	(735)
10	Scenario 4	–	–	–	–	–	(1,230)	(1,161)	(1,227)	(1,306)	(1,392)

The need determination for the portfolio of power products needed to serve PG&E’s bundled customer load is presented in Volume 1, Section IV.H.2. The annual and monthly forecasts of PG&E’s net open position for bundled customer need are located in Vol. 1, Attachment IVA. The monthly energy forecasts are shown in Tables Vol. 1, IVAX 26-37. The monthly capacity forecasts are shown in Tables Vol. 1, IVAX 38-49.

F. Price Forecasting

1. Commodity Prices

Volume 1, Section III.A.8, describes PG&E’s methodology used to develop its forward curves for electricity and natural gas. Although the plan covers the years 2007 to 2016, PG&E extended the forecast through 2036 in order to conduct life-cycle cost-benefit analysis for investments including the ones made in 2016. Additional information about PG&E’s power and gas price forecasting methodology is presented in Attachment 3 to Volume 1.

Market price risk is analyzed in two different ways: (1) risk associated with fundamental shifts in the marketplace is covered through a scenario analysis; and (2) stochastic risk is analyzed using Monte Carlo simulations of power and gas prices. Both of these approaches rely on the use of volatilities of electricity and power prices and the correlations between them, and Monte Carlo simulation approaches. Each approach is described below.

To test the robustness of a plan, several price risk scenarios were developed to represent states of the world. For Scenarios 1 and 4, a sustained low gas price forecast and a sustained high gas price scenario is used respectively. These high and low gas price forecasts are developed using the results of three thousand Monte Carlo simulations of the correlated on-peak electricity, off-peak electricity and the gas prices at a monthly level. These forecasts are generated using simulation paths that exhibit sustained high prices and sustained low prices. The current price forecast together with high and low price forecasts for gas and electricity are shown in Table Vol. 1, IVF-1. The details of this methodology can be seen in Attachment 3 to Volume 1.

TABLE VOL. 1, IVF-1
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICITY AND GAS PRICE FORECAST SCENARIOS

		On Peak Power ($/MWh)			Off Peak Power ($/MWh)			PG&E Citygate ($/MMBtu)		
Line No.	Year	Low	Forward Curve	High	Low	Forward Curve	High	Low	Forward Curve	High
1	2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5.15	7.92	11.25
5	2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.84	7.45	10.58
6	2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.64	7.14	10.14
7	2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.34	6.68	9.48
8	2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.15	6.39	9.07
9	2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3.97	6.10	8.66
10	2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.15	6.38	9.06
11	2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.35	6.69	9.49
12	2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.49	6.91	9.81
13	2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.72	7.25	10.30
14	2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.90	7.54	10.71
15	2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5.09	7.83	11.11
16	2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5.30	8.16	11.58
17	2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5.52	8.49	12.05
18	2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5.75	8.85	12.56
19	2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5.98	9.20	13.06
20	2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.19	9.53	13.53
21	2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.42	9.88	14.03
22	2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.64	10.21	14.50
23	2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.87	10.57	15.01
24	2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7.15	10.99	15.61
25	2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7.36	11.32	16.07
26	2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7.57	11.64	16.53
27	2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7.78	11.96	16.99
28	2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7.98	12.28	17.44
29	2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8.19	12.61	17.90
30	2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8.40	12.93	18.36

Using the price-risk scenario analysis, PG&E captured the effect of sustained high price and low price states of the world. However, because of the high volatility of power and gas prices, price levels can reach extremely high levels in a given month or year. This variability directly influences revenue requirements for the year. The scenario analysis does not necessarily capture this effect since in a given simulation path, the average price level for the 10 years may not be high, but prices in certain years can be extremely high. To capture this effect, because the dispatch decisions associated with generating units is daily, a daily Monte Carlo simulation is used this time using daily volatilities and correlations between electricity and gas price returns. The 95th percentile prices by year is presented in Table Vol. 1, IVF-2. The 95th percentile revenue requirements that are calculated concurrently with the prices are reported in Vol. 1, Section IV.B.4. Additional information on this methodology can be seen in Attachment 3 to Volume 1.

TABLE VOL. 1, IVF-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICITY AND GAS PRICES: 95TH AND 5TH PERCENTILE LEVELS

		NP 15 On Peak ($/MWh)			NP 15 Off Peak ($/MWh)			PG&E Citygate ($/MMBtu)		
Line No.		5th Percentile	Forward Curve	95th Percentile	5th Percentile	Forward Curve	95th Percentile	5th Percentile	Forward Curve	95th Percentile
1	2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.59	7.92	17.09
5	2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.20	7.45	16.96
6	2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.93	7.14	17.17
7	2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.65	6.68	16.30
8	2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.40	6.39	16.17
9	2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.22	6.10	16.39
10	2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.13	6.38	17.21

2. Costs by Resource Type

The properties of the fossil fired generic units considered to fill part of the open position are summarized in Table Vol. 1, IVF-3.

TABLE VOL. 1, IVF-3
PACIFIC GAS AND ELECTRIC COMPANY
GENERIC FOSSIL-FIRED UNIT PROPERTIES

Line No.		CCGT	CT
1	Ave HR at Max (Btu/kWh)	7,348	9,807
2	VOM ($/MWh)	2.43	9.95
3	Min Capacity (MW)	250	100
4	Max Capacity (MW)	500	100

The variable costs associated with generic fossil fired generation are the Variable Operations and Maintenance ("VOM") costs and the natural gas costs. The heat rate of a unit has a direct impact on the natural gas costs. The heat rate and the VOM cost for a CCGT are derived from the assumptions used for the 2005 Market

Price Referent ("MPR") methodology.[64] The heat rate and the VOM cost for a CT are derived from the 2004 MPR methodology since they are not available in the 2005 MPR methodology. The fixed costs associated with these units are calculated considering insurance, property taxes, fixed Operations and Maintenance ("O&M"), debt costs, taxes and after-tax cash flows. The in-service installed capacity costs for the units are $939/kW and $730 kW (in 2006 dollars) for Combined Cycle Gas Turbines ("CCGT") and Combustion Turbines ("CT"), respectively. These costs are also derived from 2004 and 2005 MPR methodologies. In estimating resource costs, PG&E also uses an annual inflation rate of 2%, and a weighted average cost of capital ("WACC") of 7.64% for discounting purposes.

3. RA Capacity Price

The net capacity cost of a new CT is used to represent the forward RA capacity price. The annual net cost of a CT is determined by subtracting from the CT's annual economic carrying charge[65] the annual gross margin (net energy benefit)[66] that the new plant is expected to earn from producing and selling energy in the wholesale market. The RA capacity price (or net capacity cost) is usually expressed in $/kW-year, and shown for the various price scenarios in Table Vol. 1, IVF-4. However, these prices may not be reflective of actual market prices today or in the future for RA for these periods.

The methodology for calculating the gross margin for a plant is summarized in Attachment 3 to Volume 1. Because the difference between revenues generated by selling the generated power at wholesale electricity prices minus the sum of the fuel and variable O&M costs is higher in the high price scenario than in the low price scenario, the marginal unit earns higher gross margins in the high price scenario than in the low price scenario. As a result, the unit recovers more of its fixed costs under

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[64] Resolution E-3980 - The 2005 Market Price Referents.

[65] A plant's real economic carrying charge is the annual constant dollar-denominated amount which, if escalated at the rate of inflation over the life of the plant, produces a stream of annual nominal dollar-denominated cash flows that has the same present value as the present value of the stream of the plant's annual fixed costs.

[66] A plant's net energy benefit in each period is the nominal dollar-denominated gross margins (*i.e.*, revenue minus variable costs) the plant is expected to earn in each period over its operating life by producing and selling energy. Because the new CT would be a peaking resource, PG&E assumes that a new CT would produce energy only when wholesale energy market prices exceed the variable fuel and variable O&M costs that would be incurred in using that CT to generate that energy.

the high price scenario. That is why capacity prices are lower in the high price scenario than in the low price scenario.

TABLE VOL. 1, IVF-4
PACIFIC GAS AND ELECTRIC COMPANY
RA CAPACITY PRICE
($/KW-YR)

Line No.		Based on Low Price Scenario	Based on Forward Curves	Based on High Price Scenario
1	2007	[redacted]	[redacted]	[redacted]
2	2008	[redacted]	[redacted]	[redacted]
3	2009	[redacted]	[redacted]	[redacted]
4	2010	[redacted]	[redacted]	[redacted]
5	2011	[redacted]	[redacted]	[redacted]
6	2012	[redacted]	[redacted]	[redacted]
7	2013	[redacted]	[redacted]	[redacted]
8	2014	[redacted]	[redacted]	[redacted]
9	2015	[redacted]	[redacted]	[redacted]
10	2016	[redacted]	[redacted]	[redacted]

G. Resource Trade-off Assessment

The Scoping Memo requests that the utilities provide a qualitative and quantitative assessment of the trade-off between different resources and strategies.[67] In its 2006 LTPP, PG&E has quantified and evaluated the potential trade-offs between reliability and cost, and between environmental impact and cost. Because the candidate plans use different planning reserves targets, and different mixes of preferred vs. conventional resources, their cost, risk, reliability and environmental metrics are the basis to evaluate the trade-offs between the plans and associated resource and strategies. These trade-offs are described briefly here and in more detail in Volume 1, Section VI.C.

1. Reliability Versus Cost Trade-off

All candidate plans meet the current RA requirement under the IEPR high load growth forecast and assume sufficient preferred resources are available in the market. However, given the load and resource availability uncertainties, not all plans meet minimum RA requirements or avoid the occurrence of involuntary customer curtailments under some scenarios. Therefore, for some of its LTPP candidate plans,

[67] Scoping Memo at 16.

PG&E procures additional resources at an additional cost to reduce the possibility of such events. PG&E's plans include different amounts and types of resources, resulting in different reliability and costs to illustrate the reliability vs. cost choices the Commission has in the 2006 LTPP proceeding.

2. Environment Versus Cost Trade-off

All candidate plans follow the State Loading Order. That is, under each plan, PG&E procures cost-effective preferred resources (CEE, DR, DG and renewable resources) to the extent available to meet the prescribed preferred resource targets. In some scenarios, however, there are not enough cost-effective resources to achieve the targets. Depending on the plan, PG&E may choose to procure preferred resources which are not cost-effective to meet a target. The difference in strategic paths or plans results in different cost, reliability and environmental impacts.

H. Candidate Resource Plan

This section presents the candidate procurement plans that PG&E considered, and the criteria that PG&E used to select the recommended plan. A plan is a set of procurement-related actions that PG&E proposes to undertake to meet the needs of its customers. PG&E considered three candidate plans to highlight policy tradeoffs available to the Commission with regards to the reliability, environment impacts, and cost of incremental procurement alternatives available to PG&E over the next 10-year horizon (*i.e.*, 2007-2016). The plans include demand-side, supply-side and transmission alternatives available to PG&E during this 10-year horizon.

1. Criteria Used to Develop Candidate Plans

PG&E developed three candidate plans that are feasible and implementable. To be feasible, plans must comply with prior Commission directives, meet minimum planning reserve requirements under expected load conditions, and have resources that fit the system's energy and capacity product needs. In particular, PG&E's candidate plans meet the Commission adopted minimum 15-17% PRM under the CEC IEPR high load growth forecast for a 1-in-2 temperature peak ,[68] and procure from available preferred resources amounts to meet the various State Loading Order targets for these resources. In addition to meeting the State Loading Order

[68] PG&E built its recommended plan to meet a higher than current PRM equal to 16% of a 1-in-10 peak demand forecast. PG&E provides support for this proposed PRM in Volume 2, Section IV.A.

requirements for preferred resources, PG&E's plan includes residual amounts of new dispatchable and operationally flexible resources to meet the region's reliability needs, consistent with the PRM used for the particular plan. The plans also include additional capacity and energy products to be procured from existing resources to meet residual needs of PG&E's bundled customers.

The plans also need to be implementable. That is, PG&E should be able to implement the candidate plans, and procure the amounts and type of resources assuming the Commission authorizes PG&E to procure those resources within the time window proposed by the plan. PG&E's candidate plans include demand-side, supply-side and transmission alternatives which PG&E can implement within the time frame specified in the plans.

2. Candidate Plan Descriptions

PG&E developed three candidate procurement plans. Each plan contains actions that PG&E proposes to take in the major procurement areas including CEE, DR, DG, renewable, and conventional resources, as well as the transmission needed to support procurement in these areas. The strategic direction of each plan is described below in Table Vol. 1, IVH-1, and the corresponding proposed actions are summarized in Table Vol. 1, IVH-2, and further explained in Volume 1, Section V.

The proposed actions reflect the type and amounts of power products that are needed to meet the needs of PG&E's bundled customers. To estimate the needed products, PG&E first determined the regional need for new resources described in Volume 1, Section IV.E, above. Second, PG&E estimated the capacity and energy open positions of the portfolio. These were determined hourly and aggregated by time of use period (super-peak, shoulder peak, off-peak). Finally, PG&E chose power products that fit the time of use open positions without creating large short or very long open positions under different scenarios.

TABLE VOL. 1, IVH-1
PACIFIC GAS AND ELECTRIC COMPANY
STRATEGIC DIRECTION OF CANDIDATE PLANS

<table>
<tr><th rowspan="2">Plan Elements</th><th>Basic Procurement Plan</th><th>Increased Reliability Plan</th><th>Increased Reliability and Preferred Resources Plan</th></tr>
<tr><td>Meet minimum requirements</td><td>Meets increased reliability requirement in all scenarios</td><td>Meets increased reliability requirement in all scenarios with a higher amount of preferred resources</td></tr>
<tr><td>CEE Strategy</td><td>Invest in all CEE that is cost-effective and available in the market</td><td rowspan="4">Same as Basic Procurement Plan</td><td rowspan="4">Same as Increased Reliability Plan except that PG&E procures more renewable energy and DR even if not cost-effective to achieve the higher reliability requirement</td></tr>
<tr><td>CSI Strategy</td><td>Implement D.06-01-024, following implementation details from on-going DG-OIR, regardless of cost-effectiveness, subject to market availability</td></tr>
<tr><td>DR Strategy</td><td>Procure sufficient DR to meet the 5% target if cost-effective price sensitive DR is available</td></tr>
<tr><td>Renewable Strategy</td><td>Procure to meet the 20% target without considering the cost of the resource, subject to market and transmission availability constraints. Procure renewable generation beyond 20% only if cost-effective</td></tr>
<tr><td>Transmission Strategy</td><td>Build to support renewable procurement strategy</td><td>Same as Basic Procurement Plan</td><td>Same as Basic Procurement Plan</td></tr>
<tr><td>Conventional Resource Strategy</td><td>Procure to the extent needed and to meet the system's energy and capacity product needs and to meet a 15-17% PRM under the IEPR high load growth forecast for a 1-in-2 temperature peak</td><td>Procure to the extent needed to meet the system's energy and capacity product needs and to meet a 16% PRM under all scenarios for a 1-in-10 temperature peak</td><td>Same as Increased Reliability Plan</td></tr>
</table>

a. Basic Procurement Plan

The first plan is the Basic Procurement Plan. This plan meets all basic state and regulatory requirements in effect today. Under this plan, PG&E procures sufficient resources to meet a 15% PRM under the high CEC IEPR load growth.

Also, PG&E procures preferred resources consistent with the loading order to the extent preferred resources are available in the market at or below their market value with two exceptions: (1) PG&E implements D.06-01-024 (the CSI funding decision) following implementation details from the ongoing DG-OIR, regardless of cost-effectiveness, subject to market availability; and (2) PG&E procures renewable resources to meet the 20% target without considering the cost of the resource. In order to meet its residual open position under this plan, PG&E needs the following products by 2016:

- Up to 1,900 MW of baseload generation;
- Up to 2,050 MW of shaping generation;
- Up to 1,700 MW of peaking generation; and
- Up to 3,800 MW of additional RA or peaking capacity.[69]

PG&E's candidate plans rely on increasing amounts of intermittent renewable generation to meet the RPS targets. By 2016, PG&E anticipates having wind installed generation ranging between 2,200 to 4,100 MW, depending on the scenario. Studies are under way at the CEC to determine the system's ability to manage increasing wind penetration levels. While many questions remain unanswered as to the impact of higher wind penetration,[70] in preparing its 2006 LTPP, PG&E compared the RA value of its existing wind generation against the actual output from received at the time of the CAISO peak for each month over the last three years. This analysis shows that on average, the actual output received during the peak hour in the summer

[69] The amount of RA and peaking capacity include 500 MW of additional capacity needed to integrate higher amounts of intermittent generation included in all three PG&E candidate plans. This amount was calculated as the difference between wind's RA value, and the expected deliveries at the time of the CAISO peak. These amounts also assumed the Commission approved all of the DR enhancements PG&E proposed on August 30, 2006. As explained below, D.06-11-049 approved some, but not all, of the enhancements proposed by PG&E. PG&E did not have time to reflect the effect of this decision in its 2006 LTPP analysis. In order to account for the reduced DR amounts, PG&E's need for new dispatchable and operationally flexible resources increases by approximately 200 MW in 2011. *See* Volume 1, Section IV.H.4, below.

[70] See CEC Staff responses to questions raised at the August 15, 2006 Workshop on the Intermittency Analysis Project: 2006 Renewable Baseline and 2010 RPS Scenario Results. http://www.energy.ca.gov/pier/conferences+seminars/2006-08-15_RPS_workshop/2006-11-13_RESPONSES_TO_COMMENTS.PDF.

months ranges between 0.3% to 7% of wind installed capacity, while the RA value calculated using the Commission-adopted counting rules ranges between 12% and 37% of installed capacity. On average, the gap in peaking capacity to the system is around 20% of wind's installed capacity. While this simple analysis does not address the complex planning and operational impacts of higher wind penetration levels, it shows that, at a minimum, significant additional dispatchable and operationally flexible resources are needed to close the gap between the RA counting rules and the actual wind output during the peak hour. As a result, in developing its candidate plans, PG&E includes additional amounts of peaking resources equal to the gap (approximately 20% of the installed wind generation additions) between the RA counting rules and the actual wind output during the peak hour.

The above products will be procured from existing and new resources. Considering the PG&E service area need for new resources presented in Volume 1, Section IV.E above, under this plan PG&E anticipates a need of approximately 1,700 MW of new dispatchable and operationally flexible resources for commercial operation between 2013 and 2016, with annual increments of 250 MW to 700 MW. Other products will be procured from existing resources.

In this and the other two plans, PG&E has chosen to procure dispatchable and operationally flexible resources and purchase to cover its baseload product needs from existing resources for two reasons. First, PG&E's baseload need is a contractual need in that it arises from the expiration of its allocated DWR contracts between 2010 and 2012. The resources supplying these DWR contracts are expected to continue operating after their contracts expire and should be available to sell to PG&E. Second, new dispatchable and operationally flexible resources are needed to integrate incremental amounts of intermittent renewable generation that PG&E plans to add to its portfolio.

The amounts and initial operating year of the new resource needed in this and other candidate procurement plans are shown in Table Vol. 1, IVH-2.

TABLE VOL. 1, IVH-2
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED ACTIONS BY CANDIDATE PLAN
(MW)

		Proposed New Residual Peaking and Shaping Procurement by Candidate Plan (MW)		
Line No.	Year (Summer COD)	Basic Procurement Plan	Increased Reliability Plan	Increased Reliability and Preferred Resources Plan(a)
1	2007	0	0	0
2	2008	0	0	0
3	2009	0	0	0
4	2010	0	0	0
5	2011	0	950	150
6	2012	0	1,450	1,450
7	2013	250	0	0
8	2014	700	50	0
9	2015	400	100	0
10	2016	350	300	0
11	Cumulative	1,700	2,850	1,600

(a) These amounts assume the Commission approves all of the DR enhancements PG&E proposed on August 30, 2006. As explained below, D.06-11-049 approved some, but not all, of the enhancements PG&E included in its Increased Reliability Plan and Preferred Resources Plan. PG&E did not have time to reflect the effect of this decision in its 2006 LTPP analysis. In order to account for the reduced DR amounts, PG&E's need for new dispatchable and operationally flexible resources increases by approximately 200 MW in 2011. *See* Volume 1, Section IV.H.4, below.

b. Increased Reliability Plan

The second candidate plan is the Increased Reliability Plan. Under this plan, PG&E procures to a higher reliability requirement than the current Commission-adopted RA requirement. PG&E explains the reasons for the higher planning reserve requirement in Volume II, Section I.B. The minimum reliability requirements in this plan is a 16% PRM on a 1-in-10 temperature expected peak demand. Because of this plan's higher reliability requirement, PG&E procures approximately 1,000 MW more of peaking or RA capacity products each year than under the first plan under all scenarios.

In order to meet its residual open position under this plan, PG&E needs by 2016 the same amount of energy products as in the Basic Procurement Plan. Those are:

- Up to 1,900 MW of baseload generation;
- Up to 2,050 MW of shaping generation;
- Up to 2,850 MW of peaking generation; and
- Up to 3,800 MW of additional RA or peaking capacity.[71]

In this second plan, PG&E procures the same amounts of preferred resources as in the Basic Reliability Plan. Since these first two plans only differ with regard to their supply reliability, they allow the Commission to consider the trade-off between higher reliability benefits and the higher costs of additional resources.

Considering the resources available in its service area, under this plan PG&E anticipates the need for new dispatchable and operationally flexible resources with commercial operation between 2011 and 2016, with most of the new resources needed for commercial operation in 2011 and 2012, rather than procured gradually in increments as in the Basic Procurement Plan. Other energy and capacity products identified above will be procured from existing resources.

c. Increased Reliability and Preferred Resources Plan

In this third plan, similar to the Increased Reliability Plan, PG&E procures to a higher reliability requirement than the current Commission-adopted RA requirement, that is, to a 16% PRM on a 1-in-10 temperature expected peak demand. However in this plan, PG&E also procures more preferred resources than in the previous two plans, relaxing the restriction that discretionary preferred resources must be cost-effective. The additional preferred resource additions, compared to the other two plans include:

- Up to 3,700 GWh of additional renewable energy; and

[71] These amounts assumed the Commission approved all of the DR enhancements PG&E proposed on August 30, 2006. As explained below, D.06-11-049 approved some, but not all, of the enhancements proposed by PG&E. PG&E did not have time to reflect the effect of this decision in its 2006 LTPP analysis. In order to account for the reduced DR amounts, PG&E's need for new dispatchable and operationally flexible resources increases by approximately 200 MW in 2011. *See* Volume 1, Section IV.H.4, below.

- Up to 700 MW of incremental demand response.

Because more preferred resources are used in this plan, the residual need for energy and capacity products is reduced. In this plan, the residual resource additions needed by 2016 are:

- Up to 1,600 MW of baseload generation;
- Up to 1,800 MW of shaping generation;
- Up to 1,600 MW of peaking generation; and
- Up to 4,300 MW of additional RA or peaking capacity.[72]

Considering the increased preferred resources planned, and the existing resources available in its service area, under this plan PG&E anticipates the need for up to 1,600 MW of new dispatchable and operationally flexible resources with commercial operation between 2011 and 2012. As with the second plan, these resources are needed earlier than under the Basic Procurement Plan. Other energy and capacity products identified above will be procured from existing resources.

By increasing the amount of preferred resources relative to the Increased Reliability Plan, this third plan provides useful information for the Commission to consider the trade-off between the environmental benefits and higher costs of preferred resources.

3. Procuring Additional Resources to Address Long-Term Uncertainties

As PG&E explained above in Volume 1, Section IV.A.1, there are numerous long-term uncertainties that can significantly impact procurement planning. In order to address these uncertainties and ensure reliable energy service in northern California, PG&E is proposing increasing the amount of energy and capacity that it seeks to procure under its candidate plans by 500 MW, as explained in more detail in Volume 2, Section IV.B.

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[72] These amounts assumed the Commission approved all of the DR enhancements PG&E proposed on August 30, 2006. As explained below, D.06-11-049 approved some, but not all, of the enhancements proposed by PG&E. PG&E did not have time to reflect the effect of this decision in its 2006 LTPP analysis. In order to account for the reduced DR amounts, PG&E's need for new dispatchable and operationally flexible resources increases by approximately 200 MW in 2011. *See* Volume 1, Section IV.H.4, below.

4. Impact of the Recent Commission D.06-11-049

On November 30, 2006, the Commission adopted D.06-11-049 approving some, but not all, of the enhancements to DR that PG&E proposed on August 30, 2006, which PG&E included in its Increased Reliability Plan and Preferred Resources Plan. PG&E did not have time to reflect the effect of this decision in its 2006 LTPP analysis. In order to account for the reduced DR amounts, PG&E's need for new dispatchable and operationally flexible resources increases by approximately 200 MW starting in 2011.

5. Detailed Description of PG&E's Recommended Plan

For the reasons explained in more detail in Volume 1, Section VI, PG&E recommends the Commission adopt the Increased Reliability and Preferred Resource Plan. In this plan PG&E proposes to:

- Invest in all CEE that is cost-effective and available in the market;
- Implement the CSI funding decision according to implementation details from the on-going DG-OIR, at the lowest possible cost, and subject to market availability of DG-PV;
- Procure sufficient DR to meet the 5% target;
- Procure to a higher than 20% RPS target at the lowest possible cost and even if costs to some extent are above market, subject to market and transmission availability constraints;
- Procure up to 2,300 MW of new dispatchable and operationally flexible capacity to come on line starting in 2011 in order to meet a 16% PRM on a 1-in-10 temperature expected peak demand. This amount includes 200 MW to replace the reduction in DR associated with D.06-11-049, and 500 MW for commercial contingency; and
- Procure additional energy and RA or capacity products from existing resources to meet the remaining open position.